Department of Mechanical and Aerospace Engineering

Feasibility study of powering offshore oil and gas installations with renewable energies

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A thesis submitted in partial fulfilment for the requirement of degree in

Master of Science in Sustainable Engineering: Renewable Energy Systems & the Environment

2021

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Abstract

A major source of greenhouse gas emissions from the UK offshore oil and gas industry is the generation of electric power by natural gas or Diesel. Emissions from UK offshore power generation totalled 10 Mega tonnes carbon dioxide (CO_2) equivalent in 2018, approximately 10% of the UK's total energy supply emissions. In a 2020 strategy set out by the UK Oil & Gas Authority, there is a requirement for oil and gas operators to support the UK's 2050 net zero greenhouse gas emissions target. Due to the carbon intensity of current systems, offshore power generation is a strategic focus area for emissions reduction. This project focuses on the electrification of the power generation system of three oil and gas fields in the UK North Sea – Captain, Buzzard and Golden Eagle. These are important contributors to UK hydrocarbon production and are expected to have field lives that extend into the 2030s. Two zero carbon energy sources – wind, from the 950 MW Moray East offshore wind farm, and geothermal, from coproduced water – are evaluated to determine the extent to which they could meet the combined 120 MW demand of the fields' platforms. Wind data and the power curve for the Moray East Vestas V164-9.5 MW wind turbines were used to calculate power output and annual energy yield of the wind farm. The wind farm could generate the electricity to meet 78% the platforms' energy demands. The onshore National Grid is concluded to be the best solution to provide a reliable, low carbon power supply when wind farm output is insufficient to meet demand. Implementing a solution with wind and power from the National Grid as primary and secondary electricity sources, respectively, has the potential to save over 600,000 tonnes CO_2 annually from Captain, Buzzard and Golden Eagle's power generation systems. The calculated range of theoretical thermal power output of water coproduced from the fields is 36 MW_{th} to 162 MW_{th}, however a useful purpose for this has not been identified at this time. The Buzzard Field was found to produce water at temperatures suitable for electricity generation in an organic Rankine cycle (ORC) which could be used as a baseload supply. Results from thermodynamic analysis showed that power output of an ORC system is expected to be less than 10 MW. An installed ORC device is predicted to have a mid-case payback time of 7.03 years. An economic assessment of the complete electrification of the power generation system of the Captain, Buzzard and Golden Eagle platforms was conducted using a discounted cash flow model. The project would incur high capital expenditure, and as such, is found to have negative net present value. Therefore, for electrification to occur, government subsidy or some other form of incentive is likely to be required.

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Acknowledgements

Thank you to my supervisor, Dr Paolo Capobianchi, for the support, advice and feedback offered throughout the project, it is very much appreciated.

I would also like to thank Dr Paul Tuohy and the other engineering department staff who have taught me this last year and made it an enjoyable learning experience despite the unusual circumstances.

Thank you to Alex Johnstone from Ithaca Energy and Kirsten Pasturel from ZeGen Energy who were kind enough to speak with me and share resources that were beneficial to the project.

Finally, thank you to my family for supporting me going “back to uni”.

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Nomenclature

Symbol	Description	Units
z	Height	m
P	Power	W
ρ	Density	kg/m^3
A	Area	m^2
v	Wind speed	m/s
I	Current	A
V	Voltage	V
R	Resistance	Ω
C	Capacitance	F
t	Time	s
I_C	Charging current	A
f	Frequency	Hz
ε	Permittivity of free space	F/m
d	Distance	m
Q	Thermal power output / heat transfer	W
$\dot{m}$	Mass flow rate	kg/s
c_p	Heat capacity	J/kg.K
T	Temperature	°C or K
r	Radius	m
k	Thermal conductivity	W/m.K
R	Thermal resistance	K/W
L	Length	m
W	Work	J/s
Re	Reynolds number	
u	Velocity	m/s
l	Critical dimension	m
μ	Dynamic viscosity	kg/m.s
η	Efficiency	

Symbol	**Description**	**Units**
h	Specific enthalpy	kJ/kg
D	Discount rate	

Acronyms

AC	Alternating current
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
BLP	Bridge Linked Platform
BOPD	Barrels of oil per day
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CEDA	Centre for Environmental Data Analysis
CfD	Contract for difference
CoP	Cessation of production
DC	Direct current
EOR	Enhanced oil recovery
ETS	Emissions Trading Scheme
FPSO	Floating production storage and offloading
GHG	Greenhouse gas
GOM	Gulf of Mexico
GWP	Global warming potential
HVAC	High-voltage alternating current
HVDC	High-voltage direct current
MER	Maximum Economic Recovery
NPD	Norwegian Petroleum Directorate
NPV	Net present value
ODP	Ozone depletion potential
OGA	Oil & Gas Authority
OPEX	Operating expenditure
ORC	Organic Rankine cycle
OTM	Offshore transformer module
PV	Photovoltaics
UKCS	United Kingdom Continental Shelf
USA	United States of America
WCA	West Coast of Africa

WEC	Wave energy converter
WPP	Well Protector Platform

1.0 Introduction

The energy landscape is in a state of transition with ever-increasing focus on low carbon, renewable sources of energy. Simultaneously, demand is expected to continue to grow as many developing countries continue to increase their per-capita energy usage. The challenge will be to meet this growing energy demand in parallel with a just transition from fossil fuels (coal, oil and gas). To ensure access to affordable energy and enable human development, the oil and gas industry will continue to be key in meeting the world's energy demands in the coming decades. This will however, be in the context of a reformed industry which will be under obligation to reduce its environmental impact.

1.1 Project motivation

In 2016, the UK oil and gas regulator, the Oil & Gas Authority (OGA), set out its strategy for Maximum Economic Recovery (MER UK) of hydrocarbon resources across the UK Continental Shelf (UKCS) to maximise value from the oil and gas industry. However, this strategy did not take into account the need for alignment with the UK's goal of achieving net zero greenhouses gas (GHG) emissions by 2050. A revised strategy – the OGA Strategy – was launched in 2020 which features new requirements for oil and gas operators to reduce GHG emissions and support the energy transition [1], [2]. The OGA Strategy states that "projects need to demonstrate balance of maximising value of economically recoverable petroleum and take appropriate steps to assist the Secretary of State in meeting the 'net zero' target" [3]. The Strategy sets out the aim for the UKCS to be a net zero hydrocarbon basin by 2050 and interim targets of a 50% and 90% reduction in production emissions by 2030 and 2040, respectively, compared to a 2018 baseline [4].

There have been calls by some for the oil and gas industry to be shut down to stop GHG emissions resulting from the life cycle of fossil fuel production and usage. However, in the UK, 75% of the energy consumption is provided by oil and gas [1] showing that the energy system is still highly dependent on these fossil fuels. Scotland has made great strides in decarbonising its electricity supply, where electricity demand met by renewable sources increased from 37% in 2011 to 97% in 2020 [5]. However, transport, heating and industry are still reliant on fossil fuels as an energy source. So, while oil and gas are still, and will continue to be, an important part of the overall energy mix, the negative environmental impact resulting from their exploitation is undeniable, and the industry's social licence to operate should be scrutinised.

GHG emissions associated with the oil and gas industry come from multiple sources along the value chain, from exploration and production to shipping, refining, and end use. One major source of emissions from the industry is the generation of electric power for offshore operations by natural gas and Diesel fuels. The power generated offshore is significant. In 2018, approximately 21 TWh[1] of energy was generated by the UK offshore oil and gas industry. This was approximately 6% of the energy generated in the UK in 2018, and is equivalent to Wales's annual domestic electricity consumption [6]. In terms of GHGs, the power generation resulted in emissions of 10 Mega tonnes carbon dioxide equivalent (Mt CO_2e), approximately 10% of the UK's total energy supply emissions (Figure 1, [7]). Power generation is therefore an important target area for GHG emissions reduction. Overall, it has been estimated that the emissions from the UK offshore oil and gas industry will need to reduce to 0.5 Mt CO_2e by 2050 to meet the UK's net zero target [8].

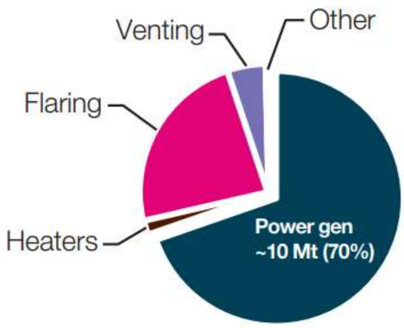


Figure 1: GHG emissions (CO_2e) from the UK offshore oil and gas industry in 2018. Power gen – power generation. Total is 14 Mt CO_2e. Flaring and venting are the ignited and unignited controlled release of gas that cannot be used, respectively. Modified after [7].

1.2 Offshore power generation

Offshore oil and gas platforms require power for round the clock operations. Hydrocarbon production is continuous and power-intensive pumps are commonly used to lift fluids from the subsurface. Concurrently, many other operations such as drilling new wells, conducting hydrocarbon flow tests and routine maintenance may be carried out. Offshore staff typically work a 12-hour shift pattern, resulting in a constant requirement for power for day-to-day living such as for cooking, lighting, heating and telecommunications.

Offshore platforms are usually isolated systems not connected to the onshore power network, and as such, use gas turbines or Diesel generators sited on the platforms for power, both of

[1] TWh – Terawatt hour (10^{12}).

which use fuels with relatively high carbon intensity (Figure 2). Gas for the turbines can be sourced by exsolving it from oil produced from the field itself but if this gas resource becomes insufficient, it is imported at expense to the operator [9], or in some cases the turbines are converted from running on natural gas to run using Diesel fuel [10]. For older oil and gas fields in particular, where production is declining, the economics can be challenged when the revenue does not exceed operating expenditure (which includes the cost of importing gas) to an extent that keeps the development financially viable. The inefficiency of power generation also impacts the economics. A study by Nguyen et al. [11], which considered the efficiency of thermodynamic processes on a UK North Sea oil and gas platform, showed that most energy is lost through the power generation system due to irreversibility in the thermodynamic processes that take place during the combustion of fossil fuels.

To reduce GHG emissions and achieve improved efficiency, electrification of the power generation system, referred to throughout this text as "electrification", of UK offshore platforms is now being considered.

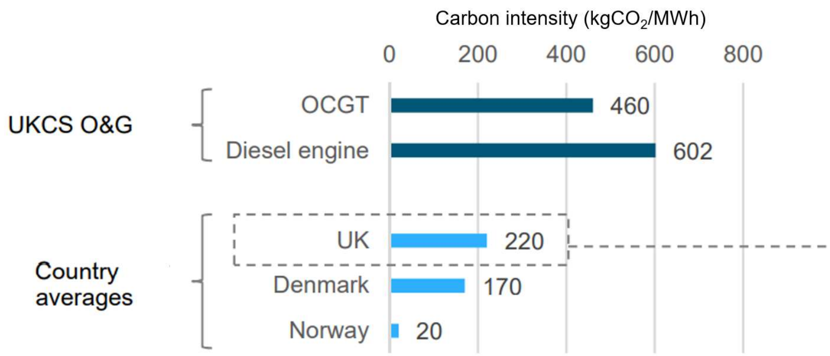


Figure 2: Carbon intensity of power generation ($kgCO_2/MWh^2$) from OCGT (open cycle gas turbine) and Diesel engine compared to UK, Denmark and Norway average carbon intensity of power generation. Modified after [6].

1.3 Platform electrification

To achieve a meaningful reduction in GHG emissions from the offshore oil and gas industry, electrification of the power generation system for installations is regarded as "essential" by industry bodies [6], albeit challenging. It is predicted that by connecting offshore platforms so that they can run at least partly on cleaner energy – from an onshore grid or directly from renewables – would achieve a step-change in emissions reduction [4]. This has also been recognised in Norway where eight offshore oil and gas fields are powered from the onshore electricity grid and there are plans in place to electrify eight others [12].

[2] MWh – Megawatt hour (10^6)

The OGA estimates that GHG emissions could be reduced by ~2-3 Mt CO_2e per year by sourcing power for UKCS platforms from the onshore electricity grid or from offshore renewables [6]. Greenfield developments (new projects) will be less complex to electrify because the design can be implemented from the beginning. Brownfield developments (existing projects) could be challenging to modify although currently, and will in the future, account for a significant amount of oil and gas production [6] and are therefore strategic for overall abatement of emissions.

Greenfield developments benefit from being able to design infrastructure with modern specifications. An example is the redevelopment of the UK Buchan Oil Field by Jersey Oil & Gas which is planning an electrified standalone facility that could act as a hub for other installations [13]. The company has stated that it believes "power from shore[3] is the most viable option", but recognises the significant costs involved. The challenge of this extends beyond cost, however. In Norway, platforms have been predominantly electrified through power from shore (expanded on in Section 1.5), but it has resulted in increased pressure on the national electricity network, and the grid operator has warned that oil and gas companies cannot rely on using it as a power source [14]. This increase in demand will require more generation capacity to feed into the network and could increase electricity prices for consumers. A study carried out prior to the 2021 G7 Summit found that 63% of people believe that government spending should be allocated to renewables rather than North Sea oil [15] and so by extension, it is unlikely that an increase in electricity prices arising from powering the offshore oil and gas industry will be socially acceptable.

Widescale electrification of UKCS installations will require collaboration between oil and gas operators so that costs and technical solutions can be shared, but the proposal is gaining traction through the OGA Strategy and companies have begun partnering in joint study projects [16]. Three ways by which a platform could receive electricity are [6]:

- Power from renewables;
- Power from UK shore via submarine cables (electricity grid);
- Power from cross-border (Norway) via submarine cables.

Economic drivers that could affect decision making are electricity prices and project capital expenditure. Power from UK shore is more expensive than power from Norway due to

[3] Defined throughout as power from the onshore national electricity grid.

difference in tariffs, network charges and wholesale electricity prices [3]. However, the OGA has stated its preference is for UK operators to source power from the UK electricity network [17].

1.4 Power from renewables

As stated in the previous section, electricity could be provided to oil and gas platforms from renewable sources. A review of the literature on powering offshore platforms using wind, wave, solar and geothermal energy is presented here.

1.4.1 Wind

There are several research and development studies into using wind power to supply offshore oil and gas platforms, and large operators are actively exploring the concept for North Sea fields [18]. A case study by Korpås et al. [19] considered the use of 4 × 5 MW wind turbines to provide power to a North Sea platform with 35 MW maximum demand. By giving wind energy priority to supply power over the installed gas turbines, the study estimated that wind could provide 40% of the energy consumption, resulting gas fuel savings and reduction in emissions from the power generation system. Aardal et al. [20] investigated using a 100 MW wind farm to provide power to five hypothetical interconnected offshore platforms with total load of 147 MW. The results of their simulations provided evidence that wind power should be given priority to supply the load because a fuel consumption reduction of up to 32% could be achieved. Integrating a 20 MW wind farm into the power generation system of a platform with 30.6 MW maximum demand was shown to achieve a 40% reduction in fuel gas consumption and GHG emissions in a study by He et al. [21] by allowing a gas turbine to operate in a start-stop manner. All three studies demonstrate the environmental benefits of utilising wind energy offshore, but consideration must be given to the stability of the offshore power system when integrating renewables. This is explored by Hu et al. [22] and He et al. [23]. Both conclude that it would be theoretically possible to maintain voltage and frequency stability, but each offshore platform-wind farm combination will be unique and would therefore need to be studied on a case-by-case basis. The load on offshore platforms can change quickly and studies by He et al. [23], Marvik et al. [24] and Årdal et al. [25] showed that wind turbines are able to respond to these changes, provided there is a wind resource available.

The offshore wind industry itself is growing rapidly in the UK. In Scotland alone, there is a target to reach 11 GW of installed offshore wind capacity by 2030 [26], a twelvefold increase on the Q1 2021 capacity of 898 MW [27]. Figure 3 shows the areas of the seabed being made available for potential wind farm development through ScotWind leasing rounds[4], and the potential growth in UK offshore wind power capacity until 2050. The leasing areas are in line with the Marine Scotland Sectoral Marine Plan which "indicates an intention to explore the demand for future leasing rounds to enable projects aimed at the decarbonisation of the oil and gas sector in Scotland" [3]. Figure 3 shows the relative proximity of wind farms and oil and gas projects, and therefore demonstrates the synergy between the industries. Offshore wind technology has traditionally been in the form of fixed turbines, but floating wind is now also being developed and Equinor's Hywind[5] Pilot Park offshore Peterhead proved its commerciality. This type of technology could benefit oil and gas platforms that are sited in deep water where fixed turbines may not be feasible.

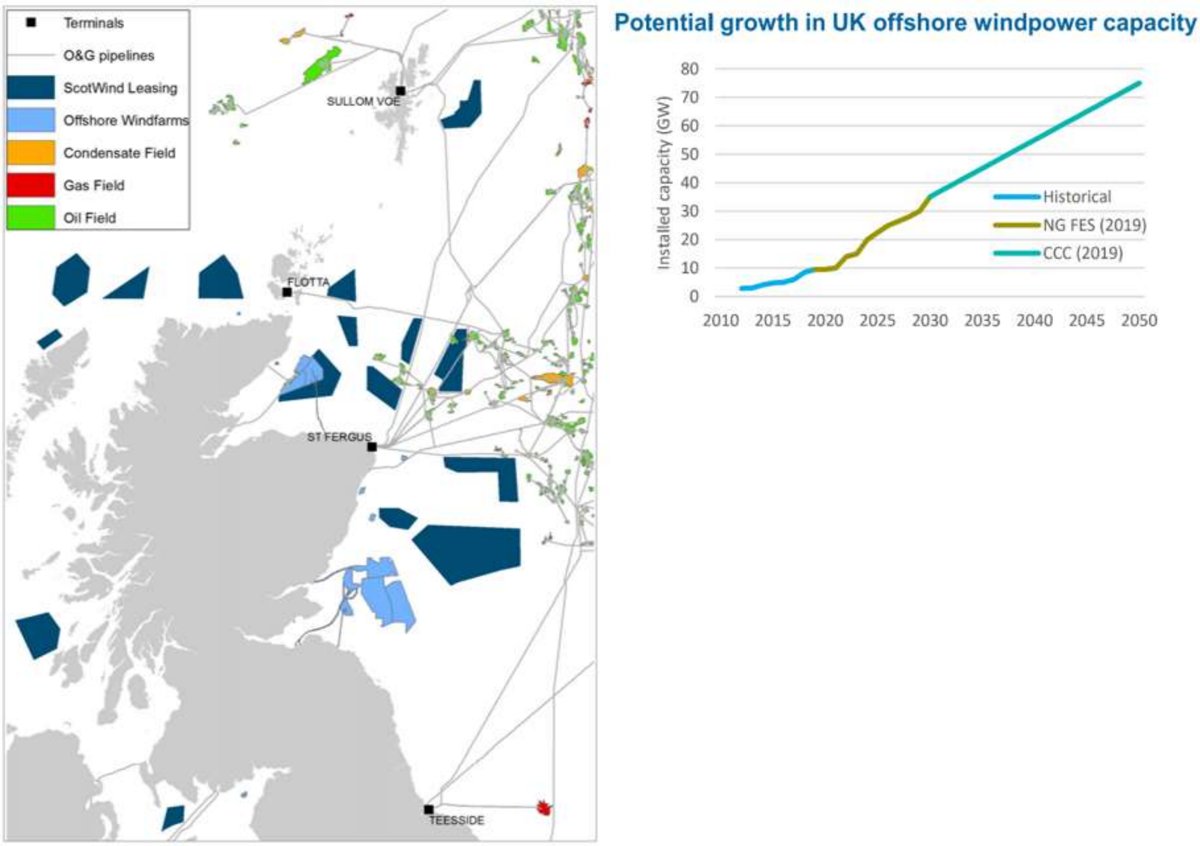


Figure 3: Left – ScotWind Leasing areas (navy polygons) [7]. Right – potential growth in UK offshore wind capacity. Trends are: historical, National Grid Future Energy Scenarios (NG FES) and Climate Change Committee (CCC) [6].

1.4.2 Wave

The global wave energy resource is estimated to be approximately 18.5 PWh/year[6] [28]. This is relatively small compared to global wind energy resource which is in the order of several

[4] Some sites are subject to "high levels of ornithological constraint" and consents may not be awarded [45].
[5] Hywind is Equinor's floating offshore wind technology.
[6] PWh – Petawatt hour (10^{15}).

hundred PWh [29]. The power of a wavefront is proportional to the square of its amplitude, therefore larger waves are advantageous for power generation. Different prototypes of wave energy converter (WEC) have been developed but convergence on the most suitable technology has not been reached [30]. Different studies have estimated the levelised cost of wave energy and it is found to be greater than other renewables (wind and tidal) and more traditional sources of energy such as natural gas [31]. This is not altogether surprising given its relatively low technical readiness level. A challenge facing wave energy is that normally, energy production from WECs is a long way from where demand exists, but this is lessened if supply to offshore oil and gas platforms is considered. Should commercial WECs come to fruition, offshore oil and gas platforms could be considered ideally located to harness ocean wave energy.

There are few studies into the feasibility of using wave energy for oil and gas platforms. Oliveira-Pinto et al. [30] present a study into the use of energy from waves for partial electrification of an offshore platform in the Norwegian North Sea, and conclude that it is feasible. This is based on the proposal of providing half of the platform's annual mean energy consumption of 237 GWh (27 MW daily power consumption; considered medium consumption level) with wave energy. The study considered seven WEC technologies and estimated that the number of installed devices required to meet the demand and provide the most favourable economics would range from 51 to 1327, depending on the technology. A second challenge facing wave energy is the harsh environment in which WECs operate. The maintenance required for this number of devices could present practical difficulties that make the solution unattractive. Nevertheless, there are studies underway researching how WECs could provide electricity offshore. One such example is a collaboration between Lundin Energy Norway and Ocean Harvesting Technologies where a case study and system design project will run until February 2022 [32].

Wave power exhibits seasonal variation outside of the equatorial regions, particularly in the northern hemisphere, where average wave power in winter can be more than three times greater than in summer [33]. It is possible that in months with lower energy generation potential, wave energy would need to be integrated with another power source.

1.4.3 Solar

Although limited in number, studies into providing power to offshore platforms from solar photovoltaics (PV) predominantly focus on locations at equatorial latitudes such as Angola by Tawiah et al. [34], and Malaysia by Tiong et al. [35], where the annual solar irradiation is relatively high. To give an indication of the magnitude, mean annual solar irradiation for the West of Africa is 1865 kWh/m^2 compared to 715 kWh/m^2 for the UK North Sea [10].

Tawiah et al. [34] show that solar power could only provide part of the 3.5 GWh/year required for the living quarters on an offshore platform in Angola, citing the limited space available to house solar panels and restrictions on weight as the limiting factors. Solar panels floating on water are suggested as a solution, but this would create practical complications that do not exist with panels fixed to the installation. Their analysis does however conclude that over a 20-year period, solar power is expected to be cheaper than using the in-place Diesel generators.

Tiong et al. [35] investigate integrating solar power with wind turbines on a platform with a 10 MW power demand offshore Borneo. These technologies are regarded as complimentary because of the seasonal weather variations, i.e., power output from solar would be lowest during monsoon season when output from wind would be greatest, and vice versa. To meet demand, multiple units of each technology would be required, but no estimate is made of the space required for the solar panels and if they could be accommodated offshore. Using an integrated solution offers advantages as stated previously, however the reliance on wind power during monsoon seasons could be challenged by climate change, which is causing weather patterns to become less predictable.

A second study that proposes combining solar with another technology is presented by Oliveira-Pinto et al. [10], where it is integrated with wave energy. For hypothetical offshore platforms each with 20 MW power demand located in the UK North Sea, Gulf of Mexico (GOM) and West Coast of Africa (WCA), the optimum combination of the two technologies was calculated based on average climatic conditions of the respective locations. Solar energy was found to have the best potential in the GOM and WCA, but for the North Sea the solar energy yield was lower than that of the chosen WEC. The mean annual capacity factor for the solar system in the North Sea was also found to be low – 6% compared to over 16% for GOM and WCA – and during winter the solar energy yield is close to zero. It was calculated that on an annual basis, the North Sea's platform demand could be met by 40% solar energy and 60% wave energy. However, based on the solar PV device used in the study, this would require panels covering an area of 3 km^2, which is not practical.

Studies have shown that it is feasible for solar to contribute some of the power requirements to offshore oil and gas platforms, but given the relatively low solar resource in UK and the large areal extent of solar panels required, it is likely that other forms of renewable energy would be favoured.

1.4.4 Geothermal

Heat derived from the ground is referred to as geothermal energy [36] and as a renewable energy source, it differs from those described in the previous sections because it is not climate-based. Traditionally associated with high temperature tectonic plate boundary settings, lower temperature applications are now also in use. Organic Rankine cycles (ORCs; explained in Section 6.5) can be used to convert the thermal energy from these low temperature sources – which can be extended to include industrial and domestic waste heat, solar heat and biomass heat [37] – into electricity [38]. Of relevance to the present project is the hot water that is coproduced with hydrocarbons in the offshore oil and gas industry. This is considered geothermal energy because the water is contained within rock formations in the subsurface.

The concept of utilising waste heat from the production of hydrocarbons is relatively new but is gaining attention in the UK oil and gas industry. The following conditions would deem oil and gas wells suitable for electricity production from geothermal energy [39]:

1. Wells in fields that are producing a large volume of water relative to hydrocarbons;
2. Wells that have been abandoned due to high water production;
3. A well in an overpressured environment producing water with dissolved gas.

Due to the maturity of the UK North Sea petroleum province, fields produce significant volumes of water, demonstrating suitability for power production based on condition 1 above. The temperature of produced water can also be high enough to be able to generate power [40]. There are more than fifty North Sea wells with geothermal gradients greater than 50°C/km [41], almost double the UK average of around 27°C/km [36], and some wells exhibit geothermal gradients of 147°C/km.

Worldwide, pilot projects have shown that power generation from coproduced fluids is technically feasible. Liu, et al. [42] describe oil fields in Wyoming, United States of America (USA) and Hebei, China that have been used as demonstration sites where electricity has been successfully generated from the low-grade heat of coproduced water. In Wyoming, more than 1900 MWh was output from an ORC in a two-year time period and in Hebei, 310 MWh was produced in nine months. The same study identified six other oil and gas fields in USA, Indonesia and Venezuela that could be used for power production. The fields' geothermal gradients range from 120°C/km to 425°C/km, which is greater than the geothermal gradient typically expected in the UK North Sea. The authors suggest that reservoir temperatures outside of the 100°C to 200°C range may not be suitable for power generation from heat recovery, but do not consider the temperature at which heat is rejected to the environment which impacts thermal efficiency (Section 6.5). Feasibility studies focused on power production through ORC power plants for offshore UK oil and gas fields have been presented by Auld et al. [9] and Younger et al. [43]. These are described further in Section 6.0, but show that ORCs utilising coproduced water have the potential to contribute a significant amount of offshore platforms' power demands.

Devices using ORCs that can be deployed offshore are being developed. A state-of-the-art modular device marketed by Climeon [44] is currently the only technology capable of reaching efficiency greater than 10%. Each module can generate up to 150 kW of electricity from hot fluids in the temperature range 80°C to 150°C and cold source temperatures from 0°C to 30°C. The water temperature of the UK North Sea (~10°C) means it is the ideal cold source which is also abundant and can be used at no cost.

The Net Zero Technology Centre considers geothermal energy to be one of the key technologies for UK and UKCS decarbonisation, but it has cost challenges and technological uncertainties and is expected to only contribute a minor amount to the overall energy mix in 2050 [45].

1.5 Electrification in Norway

In a drive to reduce Norway's CO_2 emissions, the Norwegian Petroleum Directorate (NPD) has mandated that all new petroleum developments should have the possibility of electrification. As described in Section 1.3, sixteen oil and gas fields on the Norwegian Continental Shelf currently, or will in the future, obtain their power from the onshore electricity grid, which is mostly fed by hydropower. One of these is the giant Johan Sverdrup Field which is situated 160 km offshore [46]. Another is the Valhall Oil Field which is powered from shore via a 292 km submarine cable [30]. A study by Marvik et al. [24] considers petroleum installations 280 km southwest of Norway and states that it will be possible to connect them to shore using a high-voltage direct current connection. The cost of electrification is directly influenced by the distance to shore [30], in part because the cost of submarine cables increases with length. The sixteen oil and gas fields described previously account for approximately 45% of Norway's oil and gas production and are expected be powered from shore by 2023 [47].

Some fields in Norway are now planning to receive part of their power requirements from renewables. An offshore wind farm dedicated to providing power to the Snorre and Gullfaks platforms is under development. The 88 MW capacity Hywind Tampen wind park will provide at least 35% of the platforms' power demands [48]. A final investment decision for the project was made in 2019 and the expected start up is in 2022.

1.6 Project objectives and scope

The aim of this work is to investigate the possibility of using renewable energies to provide electricity and thereby meet the platform power demands of three offshore oil and gas fields in the UK North Sea. The project objectives are:

- Calculate energy yields and assess to what extent the platforms' power demands could be met by renewables;
- Propose an electricity network layout to electrify the platforms;
- Critically assess backup power options and recommend a backup power solution;
- Carry out an economic assessment of the electrification of the power generation systems.

The project will consider three oil and gas fields in the Moray Firth region of the North Sea. The literature review showed the challenges of using wave (no convergence on suitable technology) and solar (space requirement for solar panels) technology to supply power to offshore platforms. As such, these will not be taken forward. Furthermore, any calculations of energy yields for these would be hypothetical. Focus will be on renewable sources wind and geothermal which are already, or will be, available. It is not within the scope of the project to design a detailed electricity network. However, providing a high-level overview of the options for key components and make a recommendation are within scope.

1.7 Thesis outline

This thesis contains the following sections:

- Section 2.0 describes the three oil and gas fields that will be the basis of the study, the rationale for choosing them, and the methodology leading to the estimates of power and energy demands of their platforms.
- Section 3.0 presents the choice of offshore wind farm, calculation of energy yield, the extent to which the platforms' power demands could be met with wind power and uncertainties.

- Section 4.0 explores the options for the electricity infrastructure and network layout and presents a recommendation.
- Section 5.0 presents critical analysis of backup power solutions, their associated cost and CO_2 emissions, and identifies the preferred solution.
- Section 6.0 introduces geothermal energy, its application to the offshore oil and gas industry, and the methodology and results of the calculation of thermal and electrical power output.
- Section 7.0 presents the economic assessment before final discussion in Section 8.0 and conclusions in Section 9.0.

2.0 Offshore oil and gas installations

The Moray Firth region of the North Sea will be the focus of this project. This is because it is a prolific hydrocarbon province with multiple producing fields and is in close proximity to offshore wind farm sites (Figure 4).

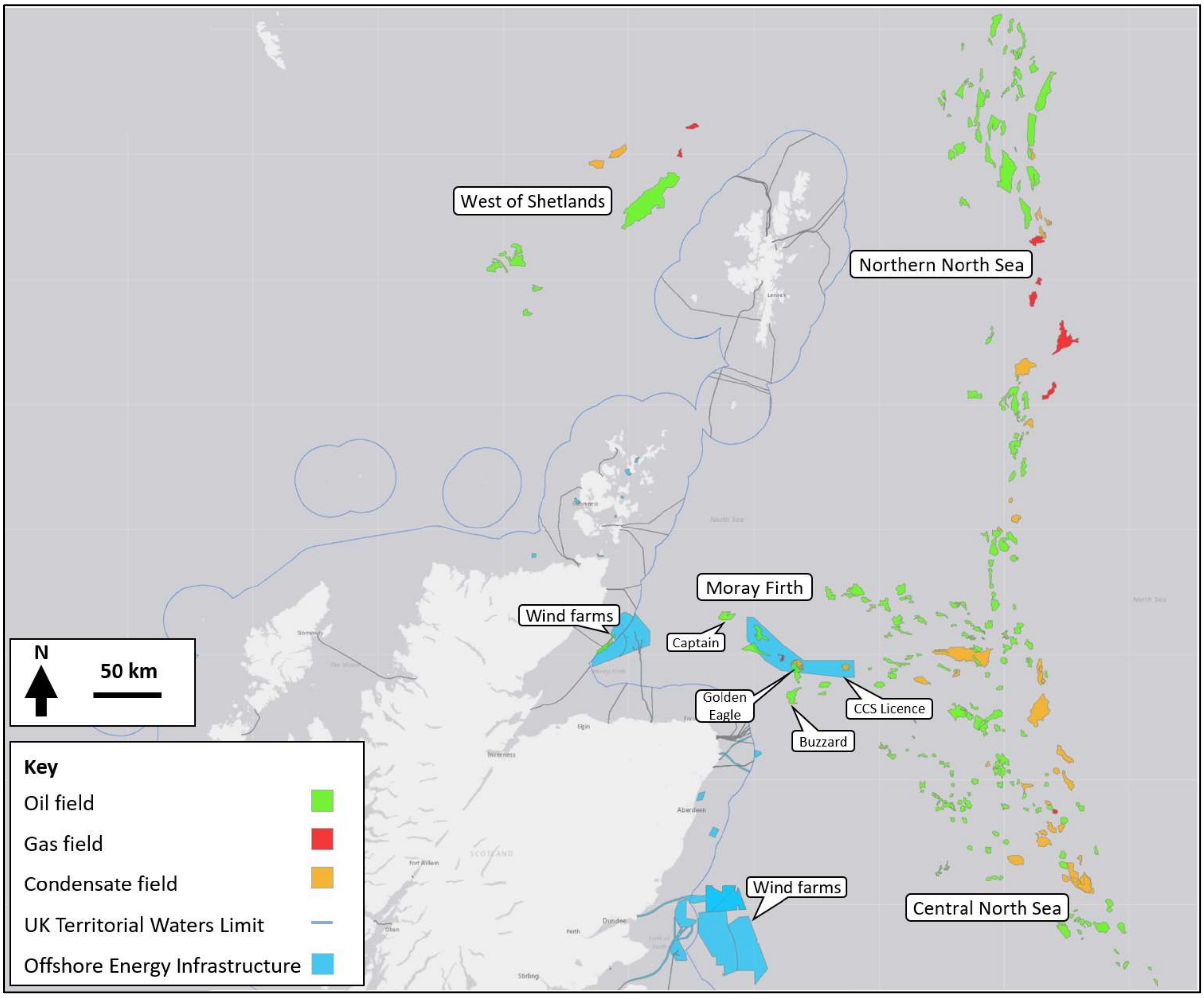


Figure 4: North Sea regions, hydrocarbon fields and location of offshore energy infrastructure. Not all wind farm areas or hydrocarbon fields are in production at the time of writing. CCS – carbon capture and storage. Map generated with data from [49].

Several oil and gas fields in the Moray Firth are developed with fixed installations (platforms) while others are developed using floating production storage and offloading units (FPSOs). Fields that are still producing have a range of Cessation of Production (CoP) dates, however the time at which CoP will occur is uncertain and depends on numerous factors. Fields with later CoP dates would be the best candidates for modifications to their installations such as electrification of the power generation system, although weight and space limitations could present a challenge for making such modifications (modifications could include the need for transformers to match frequencies, for example [30]).

The Captain, Buzzard and Golden Eagle fields, shown on Figure 4, are developed with fixed platforms and have field lives that are expected to last into the 2030s. The fields are important contributors to UK oil and gas production and could serve as hubs for future discoveries to be tied back to. It is therefore important to implement solutions to reduce their environmental impact.

This section will introduce the Captain, Buzzard and Golden Eagle fields, provide background information and quantify the power and energy demands of their platforms.

2.1 Captain Field

The Captain oil and gas field was discovered in 1977, but its heavy and viscous oil meant that production did not begin until 1997. Developments in technology such as horizontal drilling were key to unlocking its recovery [50]. Original oil in place exceeded 1 billion barrels, making it one of the biggest fields in the UKCS. Hydrocarbons continue to be recovered from the high quality Lower Cretaceous age sandstone reservoir rocks and current production is around 23,000 barrels of oil per day (BOPD)[7] [51]. The field is water flooded to improve production of the heavy oil, and this water flooding is expected to yield an ultimate oil recovery of up to 40% [52]. To increase recovery, stage one of a chemical enhanced oil recovery (EOR) project commenced in 2017 to inject the reservoir with polymer. Based on the success of the first stage, stage two of the project has been sanctioned and it is expected that chemical EOR could improve the oil recovery in parts of the field by up to 20%. The second stage of the EOR programme means that the field life of Captain is expected to extend beyond 2035 [52].

The Captain surface infrastructure consists of a Bridge Linked Platform (BLP), Wellhead Protection Platform (WPP) (Figure 5) and a Floating Production Storage and Offloading (FPSO) vessel, all of which can share power. The platforms are primarily powered by two 10 MW gas turbines and the FPSO is primarily powered by two Diesel generators [17]. Total power demand is 28 MW and is relatively stable due to the nature of the offshore operations [17]. The natural gas is sourced from the field itself through separation of the produced oil and the Diesel is purchased.

[7] Correct on 4 August 2021.

Figure 5: Captain Field BLP and WPP [53].

2.2 Buzzard Field

Discovered in 2001, the Buzzard Oil Field is the largest discovery in the UKCS since 1980 [54] with an original oil in place of greater than 1.5 billion barrels [55], and expected ultimate oil recovery of 56% [56]. However, the field has so far outperformed expectations and it is possible that the ultimate recovery could be greater. It is one of the top five producing fields in the UK, producing around 42,000 BOPD[8] [51] from Upper Jurassic age sandstone reservoirs. Hydrocarbon production began to decline in the late 2010s, and so to improve production rates and prolong field life, "Buzzard Phase II" was sanctioned. First oil from the Phase II project is expected in 2021 [57].

Buzzard is developed with four BLPs (Figure 6) supporting wellheads, production, production sweetening[9], and accommodation and utilities [58]. Power is provided by gas turbines. Gas was sourced from the reservoir at the start of field life. Once the field became fuel gas deficient, gas began to be imported [59].

Figure 6: Buzzard Field surface infrastructure of four BLPs [57].

[8] Correct on 4 August 2021.
[9] Production sweetening is a process to remove hydrogen sulphide from the hydrocarbons.

2.3 Golden Eagle Field

Eighteen kilometres north of Buzzard is the Golden Eagle Field which is being developed along with two smaller fields – Peregrine and Solitaire [60]. Discovered in 2007 and brought on production in 2014, there are estimated to be more than 400 million barrels of oil originally in place [61] within Upper Jurassic and Lower Cretaceous age sandstones [60]. The field is expected to recover 140 million barrels of oil over at least an 18-year field life [62] and is currently the ninth largest producing field in the UK, producing around 34,000 BOPD[10] [51].

Golden Eagle has two BLPs (Figure 7); one for wellheads and one for production, utility and accommodation quarters [62]. Like Buzzard, the power for Golden Eagle is provided by gas turbines using imported gas.

Figure 7: Golden Eagle Field surface infrastructure of two BLPs [62].

In the next section, the power demands of the Captain, Buzzard and Golden Eagle platforms will be quantified.

2.4 Power and energy demand of Captain, Buzzard and Golden Eagle platforms

An interviewee from Ithaca Energy [17], operator of the Captain Field, power demand data for the Captain BLP, WPP and FPSO. The total demand is approximately 28 MW and is relatively stable due to the nature of the 24-hour offshore operations. The gas turbines on the platforms provide 20 MW of power and the FPSO's Diesel generators provide 8 MW.

The same information was not available for Buzzard and Golden Eagle, and therefore data on CO_2 emissions [63] were used to calculate the energy provided to the installation from fuel gas

[10] Correct on 4 August 2021.

and its power demand. CO_2 emissions data for Captain [64] were used to calculate the inferred power demand, which was compared to the known demand of 28 MW, providing confidence in the back-calculated power demands inferred for Buzzard and Golden Eagle. Conversion factors from the UK Government [65] were used to convert from mass of CO_2 emissions to kWh of energy:

- Natural gas – 0.18282 kgCO_2 per kWh.
- Diesel – 0.24987 kgCO_2 per kWh.

Zhang et al. [66] present that the thermal efficiency of gas turbines can be between 27% and 32% and Årdal et al. [25] estimate their efficiency as being between 30% and 35%. For these calculations, it was assumed that the gas turbines and Diesel generators are 30% efficient. The average daily energy demand was calculated by dividing the annual energy output by 365. The average power demand per hour was calculated by dividing the daily energy demand by 24 (Table 1).

Table 1: CO_2 emissions and calculated energy use and power demands for Captain, Buzzard and Golden Eagle.

Installation	Fuel	2019 CO_2 emissions (tonnes)	Annual fuel use[11] (kWh)	Annual energy output – 30% efficiency[12] (MWh)	Average daily energy demand (MWh)	Average power demand per hour (MW)
Captain platforms	Natural gas and Diesel[13]	92,631 [64]	491,011,617	147,303	404	17
Captain FPSO	Diesel	74,645 [64]	298,735,342	89,621	246	10
Buzzard platforms	Natural gas	390,000 [63]	2,133,245,816	639,974	1753	73
Golden Eagle platforms	Natural gas	140,000 [63]	765,780,549	229,734	629	26

The calculated total power demand for Captain using this method is 27 MW, and the true power demand is 28 MW. This gives confidence in the results calculated for Buzzard and Golden Eagle, which were calculated to have inferred power demands of 73 MW and 26 MW, respectively. Total demand for the platforms of the three fields is therefore ~120 MW. The results are in line with data published by the OGA which shows power demand by order of

[11] Calculated by converting from tonnes CO_2 to kWh using the conversion factors presented.
[12] Calculated by multiplying the annual fuel use by 0.30 (the assumed efficiency of the gas turbines and Diesel generators).
[13] Ratio of emissions from natural gas to Diesel is ~8:1 [64]

magnitude for installations across the North Sea including Buzzard and Golden Eagle [6]. It is likely that power demand will fluctuate with time, but for this analysis it has been assumed that the demand is stable, as is the case for Captain. It should be noted that a portion of the total CO_2 emissions from Buzzard and Golden Eagle will result from gas flaring. However, the OGA consents to less than 40 tonnes of flaring per day [67] so the assumption has been made that CO_2 emissions from flaring are low compared to those from fuel gas. Going forward, the Captain fixed platforms will be taken into account only; the FPSO will not be considered because floating infrastructure will present different electrification challenges.

Monthly energy demand of the Captain platforms was calculated using Equation 1:

$$Monthly\ energy\ demand = 20\ MW\ \times 24\ hours\ \times Number\ of\ days\ in\ month \quad (1)$$

For Buzzard and Golden Eagle, Equation 2 was used to calculate the monthly energy demand from the annual energy output presented in Table 1:

$$Monthly\ energy\ demand = \left(\frac{Annual\ energy\ output}{365}\right) \times Number\ of\ days\ in\ month \quad (2)$$

The calculated monthly energy demand varies depending on the number of days in each month (Figure 8). The maximum monthly energy demand for all platforms is 89 GWh/month. Total annual demand for the platforms is 1045 GWh. The extent to which the platforms' monthly energy demands can be met by wind will be investigated in the next section.

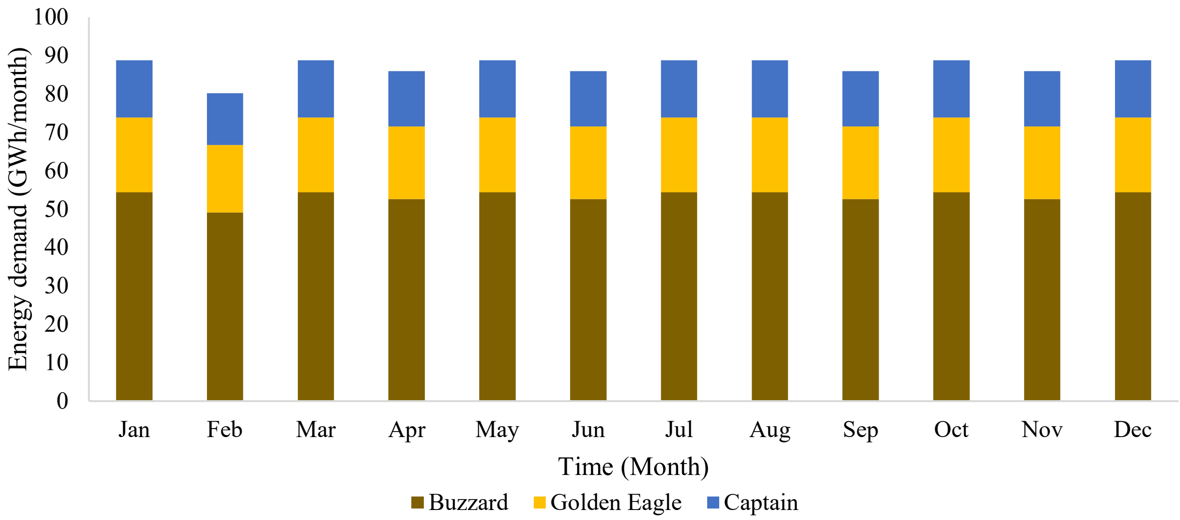


Figure 8: Monthly energy demand of the Buzzard, Golden Eagle and Captain platforms. Maximum is 89 GWh/month.

3.0 Wind energy

This section will present the offshore wind farms considered and the methodology and results of the energy yield calculation of the chosen wind farm. The extent to which the previously presented platforms' monthly energy demands can be met by wind will be investigated. Uncertainty in the analysis relating to variable wind speeds and wind turbine failure will also be considered.

3.1 Offshore wind farm selection

This project will consider existing or consented offshore wind farms only. It is possible that other wind farms will be built, however not all ScotWind Leasing sites are guaranteed to receive consent and assumptions would have to be made as to the specifications of potential wind farms. Figure 9 shows existing and consented offshore wind farms and their proximity to oil, gas and condensate fields. The Beatrice, Moray East and Moray West offshore wind farms are at a distance of ~50 km at the closest point to the locations of Captain, Buzzard and Golden Eagle. Table 2 describes the specifications of the offshore wind farms.

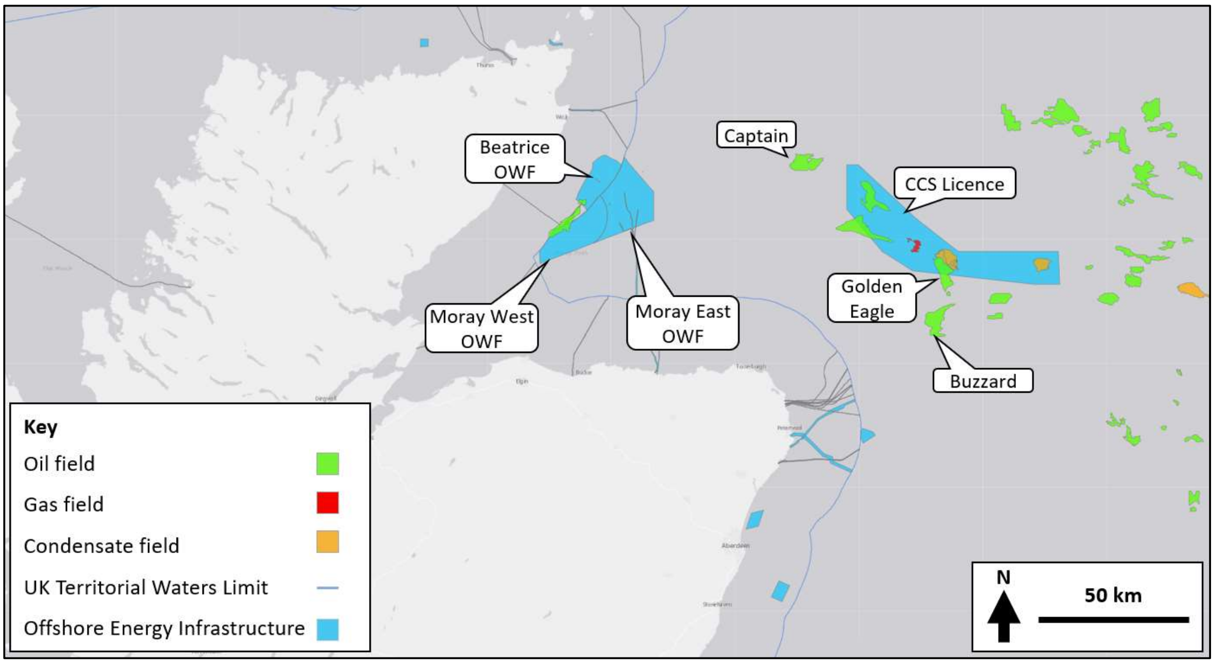


Figure 9: Map of existing and consented offshore wind farms and hydrocarbon fields. Fields are at different stages of life (some are already abandoned and decommissioned). OWF – offshore wind farm. Map generated with data from [49].

Table 2: Specifications of offshore wind farm considered for the project. Data for Moray West are not available because it has not secured a contract at the time of writing.

Offshore wind farm / Specification	**Beatrice** [68]	**Moray East** [69]	**Moray West** [70]
Operational details	Fully operational since 2019	Under construction – expected to be fully operational in 2022	Aiming to secure Contract for Difference (CfD)[14] in 2021 and begin construction in 2022-23
Capacity	588 MW	950 MW	~850 MW
Turbine model	Siemens Gamesa 7 MW	Vestas V164-9.5 MW	Not available
Number of turbines	84	100	Not available
Hub height	101 m	105 m	Not available
Rotor diameter	154 m	164 m	Not available

A decision matrix was constructed to choose the wind farm to take forward (Table 3). The four criteria used were:

- Distance to installations – shorter distance between wind farm and oil and gas installations is preferable due to cost of infrastructure.
- Development stage – the wind farms are at different stages. Beatrice is operational, Moray East is under construction and Moray West has not secured a contract at the time of writing.
- Wind farm capacity – a higher capacity could mean that the potential to route electricity to oil and gas platforms is greater.
- Opportunity for business development between wind farm developers and oil and gas operators – Moray West has the greatest opportunity for business development as it is still at the planning stage. Beatrice is already operating and would have the least opportunity for business development because modifications may need to be made to the infrastructure that is already in place.

[14] CfD definition: "The main support mechanism for large scale low-carbon electricity generation projects. Successful projects are awarded a long-term contract which secures a price to which they will either be topped up if electricity prices are low, or pay back to if electricity prices are high." [8].

Table 3: Decision matrix to select offshore wind farm to take forward.

Wind farm / Decision criteria	Distance to installations	Development stage	Wind farm capacity	Opportunity for business development	Sum
Beatrice	2	3	1	1	7
Moray East	3	2	3	2	10
Moray West	2	1	2	3	8

Electricity surplus has not been considered as a category. All have significant capacities and an electricity surplus comparison cannot be made between wind farms due to lack of required data for Moray West. Based on these criteria, the Moray East offshore wind farm scored the highest and was taken forward for this project.

3.2 Moray East offshore wind farm

Wind data were sourced from the Centre for Environmental Data Analysis (CEDA) [71]. There were no data available for the offshore Moray East site; the nearest site for which data were available is the Wick Airport weather station. A study by Watson and Soler-Bientz [72] showed that correlation between offshore and onshore sites were greater when the onshore site is coastal, as Wick Airport is in this case.

3.2.1 Wind speeds

Hourly mean wind speeds in knots at Wick Airport weather station were converted to m/s. Data for the year 2019 were used because this was the most complete weather file for the last five years. There were a small number (39) of no value hours where no data were recorded; the wind speed at these hours was set to zero, rather than using interpolation, for the purpose of the calculations. It has been assumed that the weather station instruments used to record the data were calibrated correctly.

Wind speeds vary vertically due to pressure gradients increasing with height and air density and surface friction decreasing with height [73]. Therefore, Equation 3 which is reported below, was used to correct the wind speeds measured at the weather station anemometer to the wind speed at the wind turbine hub height, u_{hub} [74]:

$$u_{hub} = u_{anem} \cdot \frac{\ln\left(\frac{z_{hub}}{r_0}\right)}{\ln\left(\frac{z_{anem}}{r_0}\right)} \tag{3}$$

where u_{anem} is the wind speed at the weather station anemometer (m/s), z_{hub} is the wind turbine hub height (105 metres; m), r_0 is the roughness length (0.01 m) and z_{anem} is the anemometer height (36 m). Figure 10 shows the hub height corrected wind speeds, which are 13% faster than those measured at the anemometer. The resulting annual hub height corrected mean wind speed is 6.6 m/s.

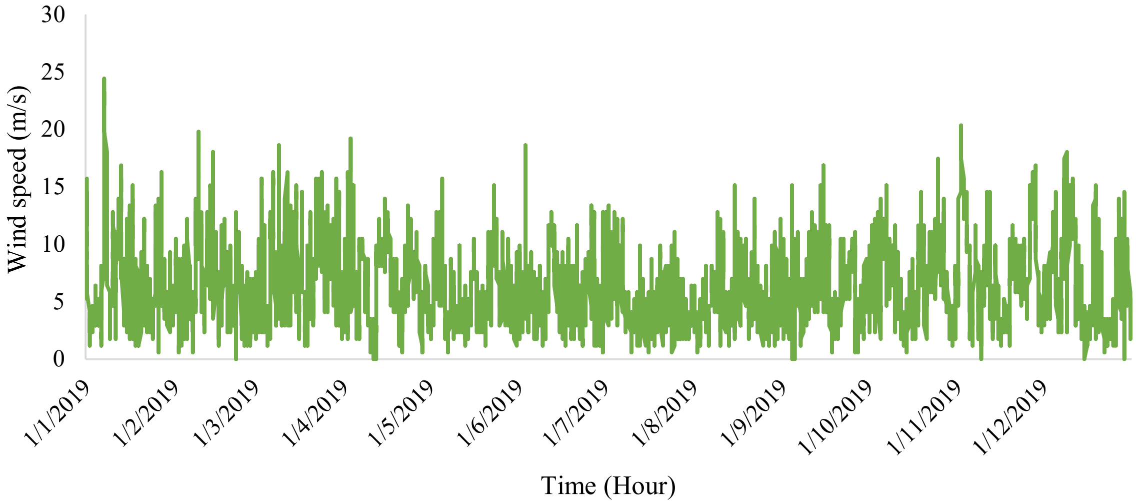


Figure 10: Hub height corrected wind speed based on 2019 weather data calculated using Equation 3.

The hub height corrected wind speeds were compared with offshore wind speeds from the ABPmer UK Renewables Atlas [75]. Figure 11 shows that wind speed increases with distance from the coast and towards the area of the wind farm. From the Atlas, annual mean wind speed within the Moray East area is approximately 9.5 m/s, indicating that the hub height corrected wind speeds calculated using Equation 3 and shown in Figure 10 are underestimated for the offshore location.

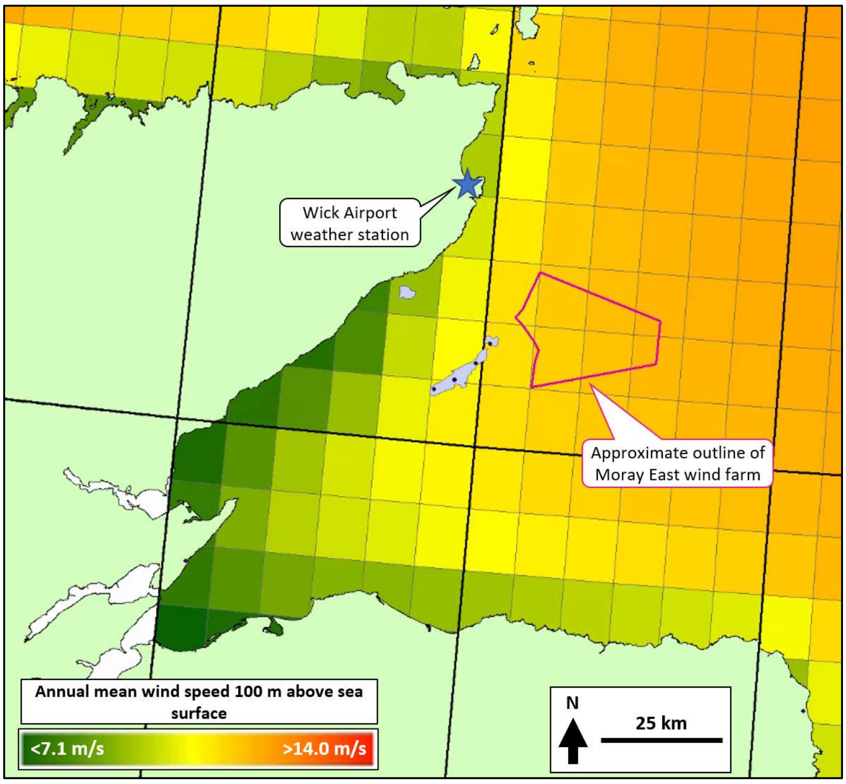


Figure 11: Annual mean wind speed 100 m above sea surface from ABPmer UK Renewables Atlas [75]. Location of Wick Airport weather station is shown in relation to the Moray East wind farm.

Hub height corrected mean wind speed per month was compared to the equivalent from the UK Renewables Atlas (Table 4). It is shown that the hub height corrected mean wind speed is underestimated for all months and the difference is greater for winter months. Equation 3 makes a correction for elevation only, and comparing with the wind speeds presented in the UK Renewables Atlas showed that a further correction was required.

Table 4: Monthly hub height corrected mean wind speed (from Equation 3), equivalent mean wind speed from the UK Renewables Atlas for Moray East site, and percentage difference between each.

Month	Hub height corrected mean wind speed (m/s)	Mean wind speed 100 m above sea surface at Moray East site from UK Renewables Atlas (m/s)	Percentage difference (%)
January	6.8	11.8	73.0
February	6.6	11.1	69.4
March	8.2	10.2	24.9
April	7.1	9.3	29.9
May	6.0	7.8	31.4
June	6.1	7.8	27.5
July	5.2	6.7	28.2
August	5.5	7.4	34.5
September	6.4	8.6	35.3

Month	Hub height corrected mean wind speed (m/s)	Mean wind speed 100 m above sea surface at Moray East site from UK Renewables Atlas (m/s)	Percentage difference (%)
October	6.9	10.8	56.0
November	7.5	11.5	52.0
December	6.6	11.1	68.5

The hourly hub height corrected wind speed was scaled up by the percentage difference shown in Table 4. This increased the annual mean wind speed to 9.5 m/s (from 6.6 m/s) which is aligned with the Atlas as well as thirty year (1984 to 2014) long term mean wind speed in this area reported by the UK Government [76]. The resulting scaled hourly profile of wind speed is shown in Figure 12 and histogram in Figure 13. The histogram exhibits a Weibull statistical distribution, which is expected for wind speed at a given site [29]. The scaled wind speed profile was taken forward for the power and energy generation calculations.

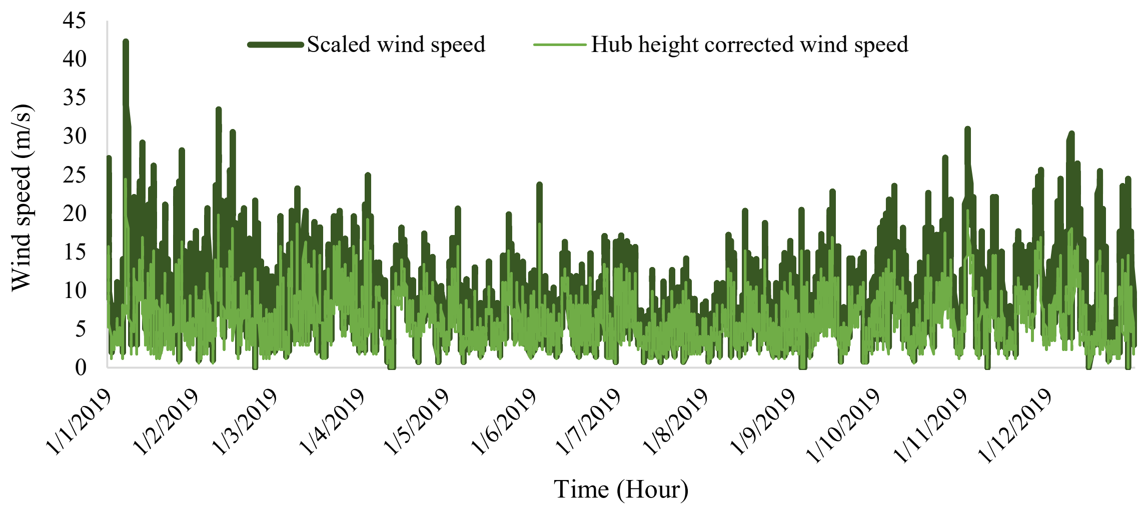


Figure 12: Scaled wind speed, calculated using percentage difference presented in Table 4, and hub height corrected wind speed from Figure 10.

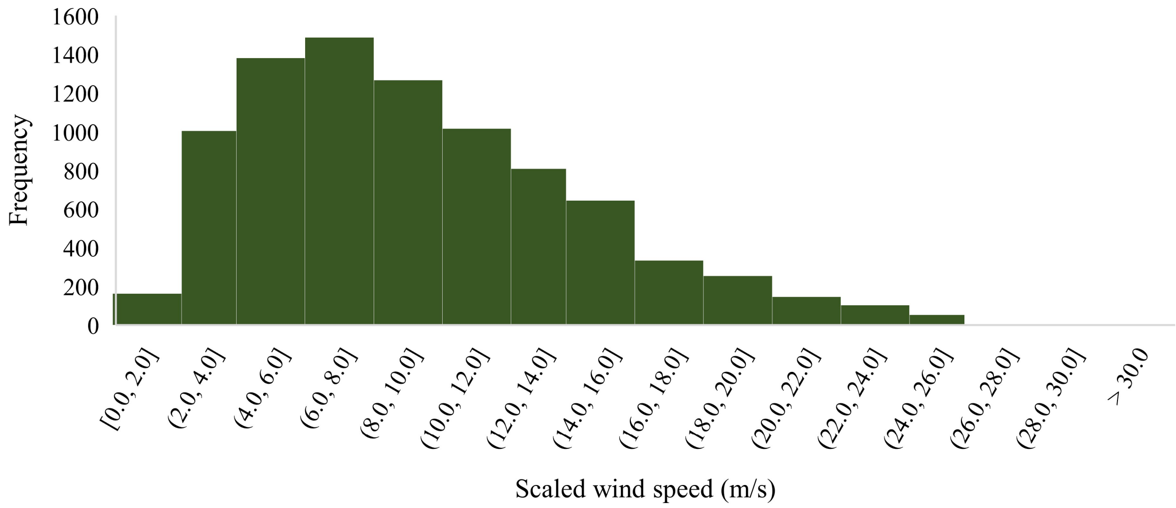


Figure 13: Histogram of scaled wind speed at the wind farm site showing a Weibull distribution. Wind speeds between 6 m/s and 8 m/s are most common.

3.2.2 Moray East offshore wind farm turbines

Wind turbines convert kinetic energy from the wind into mechanical then electrical energy. The turbine blades, of which there are three for typical installations, will begin rotating once the wind speed reaches the *cut-in* speed and continue until the *cut-out* speed is reached, when the blades stop turning for safety reasons. The maximum power output is the *rated power* which is achieved at wind speeds between the *rated* and *cut-out* speeds. Inside the 'nacelle' – the main body of the turbine situated behind the blades – a rotor, shafts and gearbox feed into an electricity generator (Figure 14). The electricity is transmitted from the turbine through electric cables. Modern turbines have a system that enables the angle of the blades to be altered to maximise the amount of power generated [77] depending on the direction of the wind.

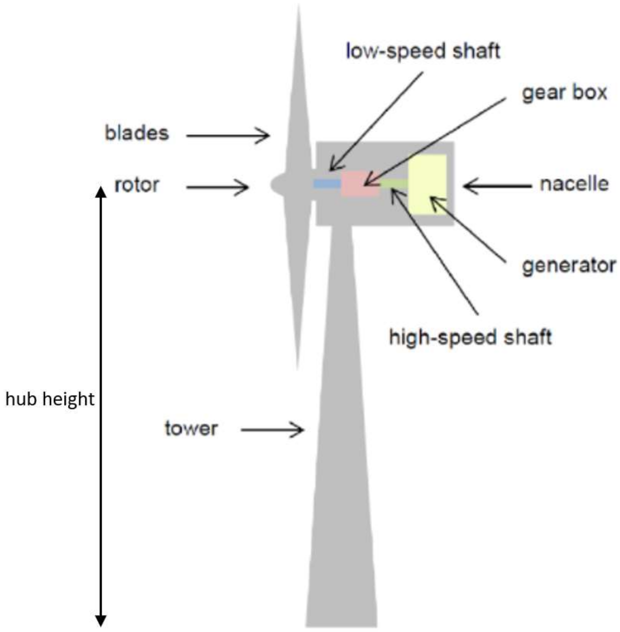


Figure 14: Cross section of wind turbine showing key features. Modified after [78].

The capacity of wind turbines, i.e., the maximum power that can be generated in optimal conditions [79], can range from a few hundred kilowatts (kW) on the smaller scale to MW capacity. The capacity is limited by the coefficient of performance – the ratio of the power captured by the turbine to the rated power – which depends on the characteristics of the turbine and its site. The size and capacity of wind turbines is continuously increasing. Between 2000 and 2019, the average capacity of an offshore wind turbine increased by a factor of 3.4 [80] (Figure 15). The advancement in turbine rating has, in reality, been quicker than shown in Figure 15, with Vestas already marketing a 236 m rotor diameter 15 MW capacity turbine.

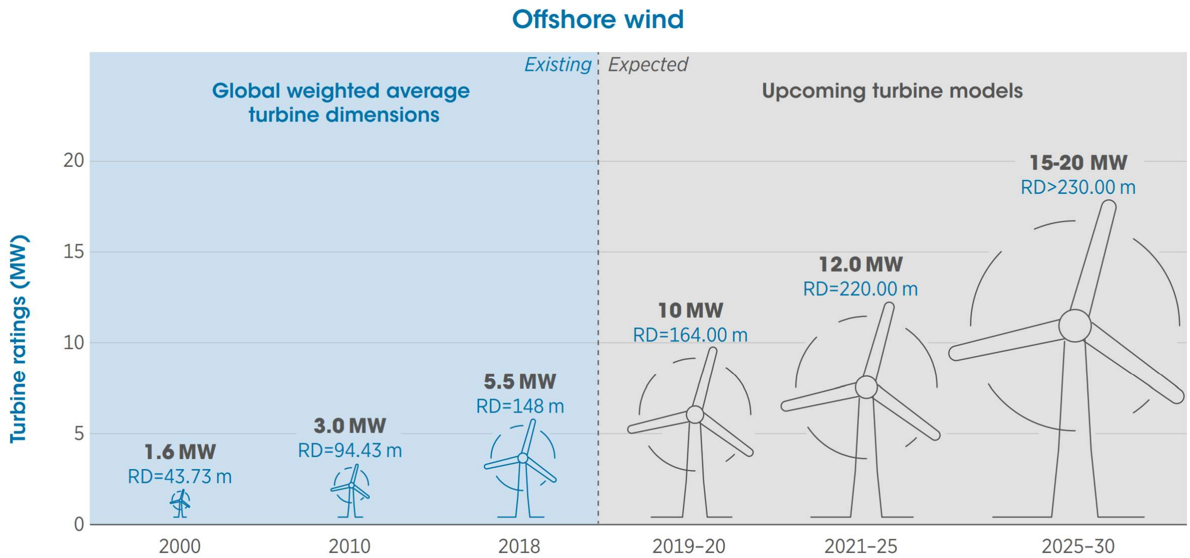


Figure 15: Existing and expected capacity of offshore wind turbines between 2000 and 2030. RD – rotor diameter. [80].

The turbine model that will be used at the Moray East offshore wind farm is the Vestas V164-9.5 MW; its key specifications are listed in Table 5. For the wind speeds shown in Figure 13, and the cut-in and cut-out speeds in Table 5, the number of annual utilisation hours of the wind farm is approximately 8000.

Table 5: Moray East offshore wind farm turbine specifications [69], [81].

Moray East wind farm turbine specifications	
Turbine model	Vestas V164-9.5 MW
Number of turbines	100
Cut-in speed (m/s)	3.5
Rated speed (m/s)	14
Cut-out speed (m/s)	25
Coefficient of performance, rated	0.268
Rated power (kW)	9500
Hub height (m)	105
Rotor diameter (m)	164
Swept area (m^2)	21,124

3.2.3 Power and electricity generated by Moray East offshore wind farm

The power curve for the Vestas V164-9.5 MW turbine [81] was used in a self-built Excel tool to determine the power output per hour for the corresponding wind speed. The coefficient of performance was calculated using Equation 4 [29]:

$$Coefficient\ of\ performance = \frac{2 \times P \times 1000}{\rho \times A \times v^3} \tag{4}$$

where P is the power output (kW), 1000 is the conversion factor between kW and W, ρ is the density of air (1.225 kg/m^3), A is the swept area of the rotor blades (m^2) and v is the wind speed on the power curve (m/s). The power curve and calculated coefficient of performance of the turbines is presented in Figure 16. The calculated values of coefficient of performance are consistent with other studies that analysed the performance of the Vestas V164-9.5 MW turbine [82], [83]. The maximum coefficient of performance is 0.476 at 8.5 m/s wind speed which is within the Betz Limit[15] of 0.593. Assumptions made when calculating power output were:

- Possible wind speed fluctuations across the wind farm site were neglected.

[15] The Betz Limit is the theoretical maximum coefficient of performance for a wind turbine; no more than 59.3% of the kinetic energy of the wind can be converted into mechanical energy. Wind turbines cannot achieve the Betz Limit because of turbine energy losses.

- The wind speeds convert to an electrical generation output defined by the Vestas V164-9.5 MW ideal power curve (Figure 16).
- No sea surface roughness was taken into account.

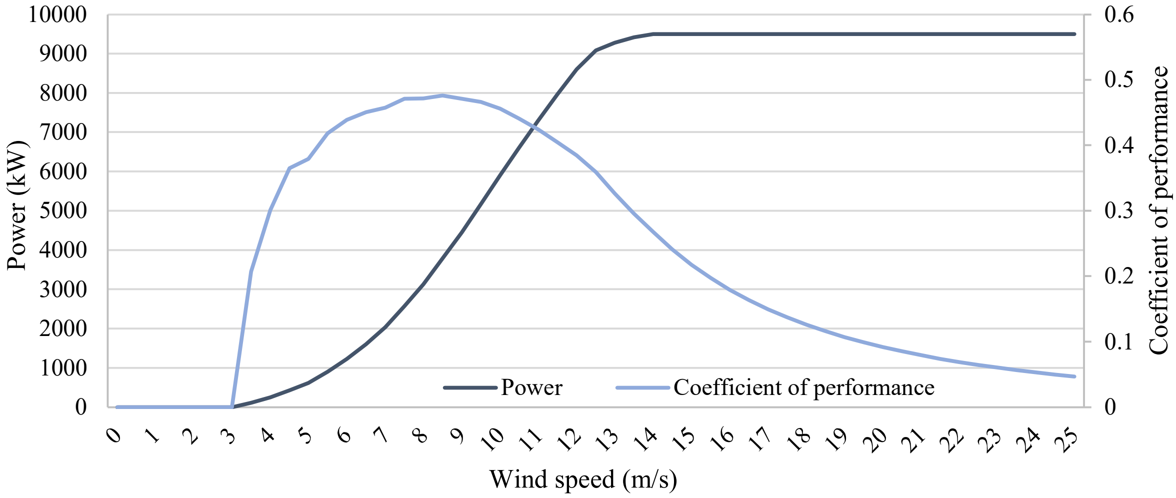


Figure 16: Power curve and calculated coefficient of performance for the Vestas V164-9.5 MW wind turbine.

The graph of power generated from one turbine in one year is shown in Appendix A. The turbines were found to reach rated power output on 1531 hours of the year, or 17.5% of the time (Figure 17).

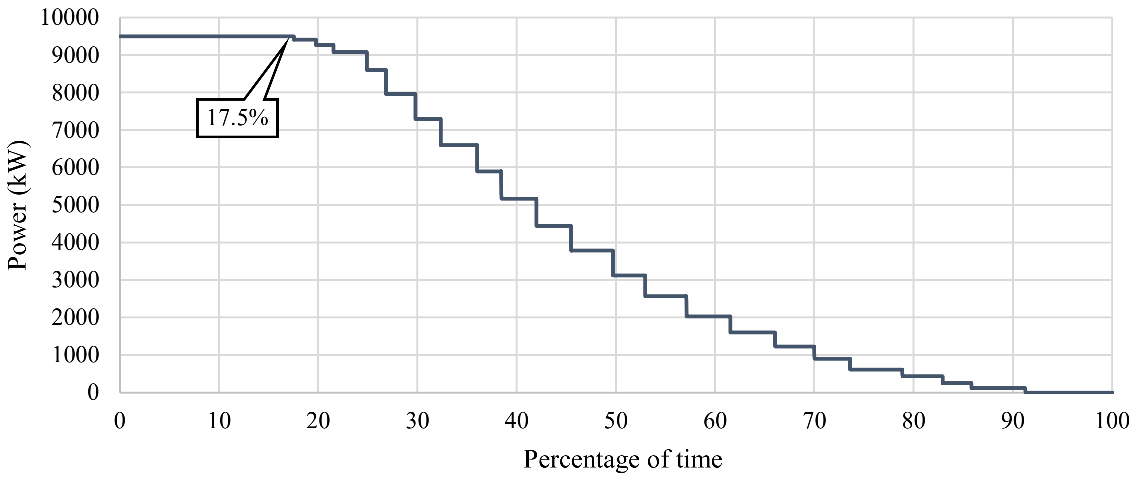


Figure 17: Duration curve for power output of one wind turbine. Rated power (9500 kW) is reached 17.5% of the year (1531 hours).

The power generated per turbine was multiplied by the total number of turbines (100; indicated in Table 5) and the power for each hour summed to calculate the potential annual electricity generation; this was found to be 3782 GWh/year. Based on an average annual UK electricity usage of 3940 kWh per home [84], 3782 GWh/year would imply that approximately 960,000 homes could be powered. This is in line with the estimate of 950,000 to one million homes stated by the developers of Moray East [69].

As per the methodology presented by Oliveira-Pinto et al. [10] when evaluating solar and wave energies for powering offshore oil and gas platforms, monthly electricity generation was found by summing the hourly power generated every day across each month (Figure 18). Stafell and Green [85] describe that the methodology of summing hourly wind speed data from a weather station should give accurate estimates of monthly electricity generation. It was found that the winter months have the potential to generate the greatest amount of electricity and July has the lowest generation. This is aligned with the wind speeds in these months, where the winter months have the highest mean wind speeds and July the lowest (Table 4).

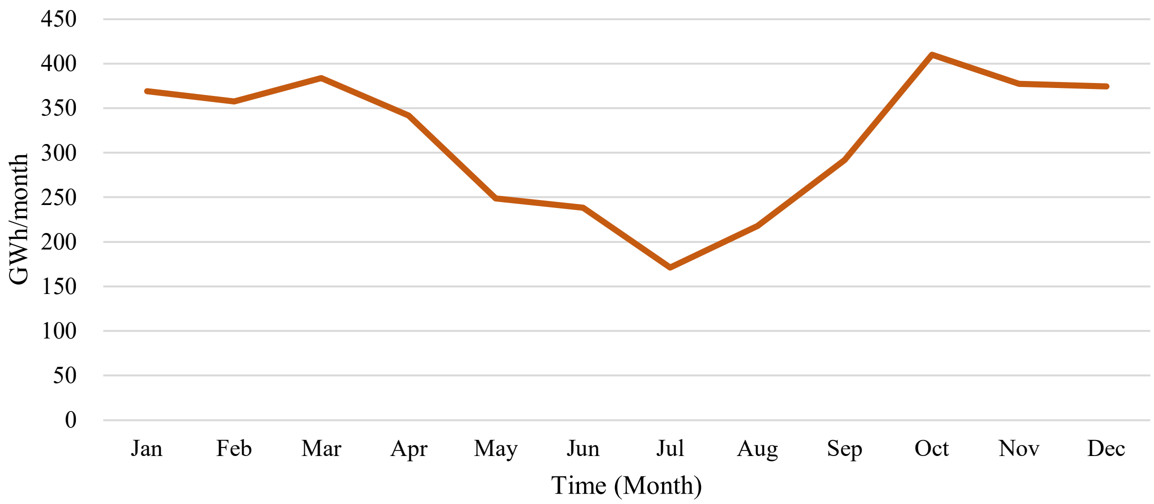


Figure 18: Potential electricity generation per month by Moray East wind farm (100 turbines).

3.2.4 Comparison with platforms' energy demands

Comparing the platforms' monthly energy demands with the electricity generation of the wind farm shows that in the case that all turbines are operating, and wind conditions are of those modelled, the supply exceeds demand (Figure 19).

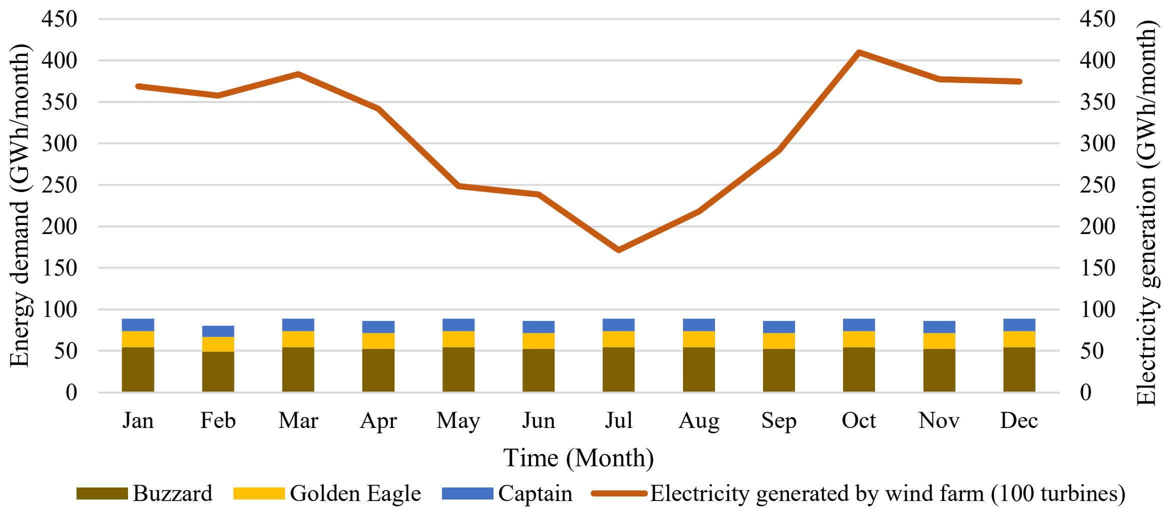


Figure 19: Field energy demands and potential electricity generation by Moray East wind farm.

Figure 19 shows that there would be a considerable surplus to export to the electricity grid. The number of homes that could be powered with the surplus is presented in Table 6. The next section will consider the uncertainty around this result.

Table 6: Monthly electricity surplus after providing power to the platforms and number of homes that could be powered with the surplus (rounded to the nearest 5000). Monthly average electricity use of one UK home assumes that the average annual electricity usage is 3940 kWh per home [84].

Month	**Surplus electricity (GWh/month)**	**Average electricity use of one UK home (kWh/month)**	**Number of homes powered**
January	280	335	835,000
February	277	302	920,000
March	295	335	880,000
April	256	324	790,000
May	160	335	480,000
June	153	324	470,000
July	83	335	245,000
August	129	335	385,000
September	206	324	635,000
October	321	335	960,000
November	291	324	900,000
December	286	335	855,000

3.2.5 Wind speed variability

Considering generation and demand on a monthly basis, July is when overall supply is lowest and generation could be at risk of being exceeded by the demand (Figure 19). For the demand to exceed supply for the full month of July, possible conditions would be:

- Wind speeds consistently 76% of the hourly values used or consistently greater than the cut-out speed of the wind turbines (25 m/s, indicated in Table 5);
- 47 of the 100 turbines not operating for the full year;
- A combination of the above.

The wind speeds used to calculate electricity generation were scaled based on data from the UK Renewables Atlas (described in Section 3.2.1), and so wind speed variability at the wind farm site itself could not be assessed. Wick Airport weather station is considered to be an analogue location, therefore wind data recorded at the weather station were checked for variability. Figure 20 shows the percentage difference between the recorded hourly wind speeds in July 2019 and those recorded in July 2012 to 2015[16]. A line at 76% is also shown. Hourly wind speeds in the years presented do drop below 76% of 2019 wind speeds, however it is not observed to be sustained over the full month. It is therefore concluded that, by extension, it would be unlikely that wind speeds at the Moray East site would show a persistent decrease across the full month of July compared to the wind speeds used to calculate energy yield.

[16] The years in the last ten with a complete dataset for July.

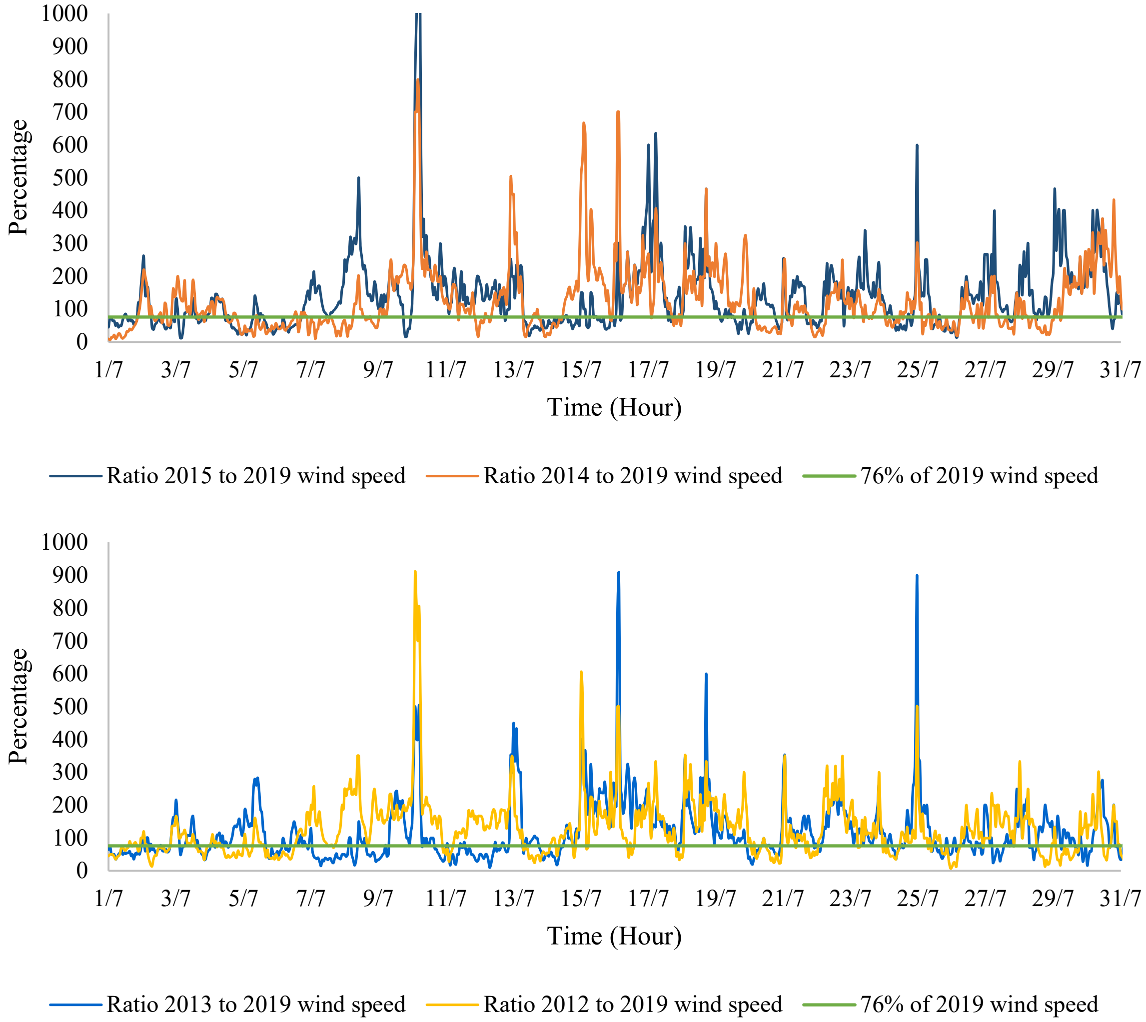


Figure 20: Percentage difference between hourly wind speeds recorded in July 2019 and July 2012 to 2015 at the Wick Airport weather station.

It is not considered a risk that wind speeds would consistently exceed the wind turbine cut-out speed of 25 m/s. The turbines would have been selected to maximise energy yield at the wind farm location based on the expected wind conditions. Mean wind speed in July of 6.7 m/s is reported for the Moray East wind farm site by the UK Renewables Atlas (Table 4), and is 11.8 m/s in January when wind speeds are highest, showing that on average, the 25 m/s cut-out speed is not close to being exceeded.

This analysis considers energy over a monthly period. However, it should be taken into account that that the power output is dynamic and wind is inherently intermittent and unpredictable. This will be addressed in Section 5.0.

3.2.6 Wind turbine failure

The calculation of electricity generation (Figure 18) assumes that all 100 wind turbines are operating constantly. It has been calculated that there would be a supply deficit in July if 47 turbines were not operating. Turbines are designed to be reliable throughout their life, but it is inevitable that there will be some system failures requiring repairs and replacement, particularly in the harsh offshore environment [86]. Data and studies on failure rates of offshore wind turbines are limited. Carroll et al. [87] present results analysing "failure rates and resource requirements for repair of modern multi-MW scale offshore wind turbines and their sub-assemblies" based on ~350 turbines "from a leading manufacturer" that are in operation across Europe. The turbines included in the study by Carroll et al. [87] have rotor diameters between 80 m and 120 m and rated power between 2 MW and 4 MW. The Vestas turbine of Moray East has a rotor diameter of 164 m and rated power of 9.5 MW. Although this turbine has undergone testing to optimise its performance and reliability across its life cycle [88], there are no published failure rate data. In the absence of this, the study by Carroll et al. [87] has been used to estimate potential down time of the wind farm.

Carroll et al. [87] found an average overall failure per turbine per year of 8.3, with the pitch and hydraulic systems[17] being the biggest contributor to this out of 19 categories considered. Average repair time was also presented for each category. Considering these data, in a worst-case scenario that all failures occurred in one year, the repair time for one turbine would be 110.9 hours, or 4.6 days. If 47 turbines experienced all failures in one year, the total repair time would be 217.2 days and could therefore be repaired within one year. It is considered unlikely that all 47 turbines would experience all failures in one year and as such true repair time would be less than 217.2 days. Therefore, the risk of 47 turbines not operating for a full year is considered to be low.

As described by authors Hughes [89] and Stafell and Green [85], it is expected that the performance of the wind turbines will decline over time, which is the same for all machinery. Because of this, a decision will be taken on repowering Moray East 15 to 20 years after commencement of operation to decide whether to replace turbines and cabling. If repowering is not carried out, the wind farm will be decommissioned at year 25 [90].

[17] The pitch and hydraulic system optimise the turbine blade angle to harness the maximum energy from the wind while it is rotating.

The same aforementioned study on UK wind farms by Stafell and Green [85] found that wind turbines lose output every year at a similar rate to other types of rotating machinery, partly due to reduced aerodynamic performance that affects conversion efficiency. Over 20 years, the degradation could reduce a wind farm's output by 12%. If Moray East was to lose output to this extent, the monthly electricity output in July – the month with the lowest electricity generation – could decrease from 171 GWh (Figure 18) to 151 GWh. This would still be sufficient to meet the 89 GWh combined monthly energy demand of the Captain, Buzzard and Golden Eagle platforms.

In this section, it has been shown that the electricity output from Moray East offshore wind farm would more than likely be sufficient to meet the energy demands of Captain, Buzzard and Golden Eagle over a monthly basis. The next section will investigate the electrical infrastructure and network layout required to route electricity from the wind farm to the platforms.

4.0 Electrical infrastructure and network layout

In this section, the main components of the electricity network required for electrification will be investigated. It is beyond the scope of this project to create a detailed design of the electricity infrastructure or analyse the effect of wind energy on power balance and stability. For further information, the reader is referred to the analysis reported in [23] - [25] which have shown that wind turbines can respond to changes in load more rapidly than gas turbines. Fundamentally, the electricity transmission and distribution system must provide the power that is required at all times, and maintain stable voltage and frequency [91].

4.1 Electricity transmission and distribution

The output voltage of the Moray East wind turbines is 66 kV [92], which is considered medium voltage and not suitable for electricity transmission at long distances [91]. Offshore substation platforms, or offshore transformer modules (OTMs; Figure 21), will transform the output voltage of the wind turbines to a transmission voltage of 220 kV – considered high voltage [93]. Submarine cables will transmit electricity from the OTMs to an onshore substation, where a transformer will raise the voltage to 275 kV, matching the voltage of the national electricity transmission network [94]. Equation 5 gives the current associated with the transmission voltage and Equation 6 gives the resulting power losses [91]:

$$P = I \times V \tag{5}$$

$$P_{loss} = I^2 \times R \tag{6}$$

where I is the current (Ampere, A), V is voltage (Volt, V) and R is resistance (Ohm, Ω). To transmit 950 MW of power at voltages of 66 kV and 220 kV, and considering a transmission resistance of 1 Ω, the power losses would be 207 MW and 19 MW, respectively. Therefore, a transmission voltage of 220 kV reduces power losses by more than ten times compared to transmission at 66 kV.

Figure 21: Offshore transformer module for Moray East wind farm, where output voltage from the wind turbines will be transformed from 66 kV to the transmission voltage of 220 kV [93].

4.1.1 Electricity network layout

Two possible electricity network layouts are proposed in Figure 22. These are: (a) direct parallel cabling; and (b) shared cabling. In Figure 22a, the electricity would be directed from the wind farm to the oil and gas platforms using dedicated parallel cabling. Advantages of this would be:

- Oil and gas platform owners avoid entering into commercial negotiations over shared infrastructure with other operators.
- A failure in a transmission cable would only affect the platform(s) connected to that cable.

However, disadvantages of the layout could be:

- Higher capital expenditure as all fields will require equipment such as transformers.
- Limited space for platform modifications may mean that a separate structure to host necessary equipment is required for all fields.
- Longer transmission distances to Golden Eagle and Buzzard compared to Captain could mean that a different transmission strategy is required for those fields, adding complexity.

Figure 22b shows an alternative layout, where electricity is transmitted from the wind farm to a 'distribution hub' where power could be distributed to the oil and gas platforms. This is a solution proposed by [6]. The advantages of this would be:

- Shared cost of electrical infrastructure between platform operators.
- Space is saved and the need for platform modifications reduced because the voltage transformer is sited separately.
- Electricity arrives at the oil and gas platform at the correct voltage and frequency for use.
- More platforms could connect to the shared distribution hub in future.

Disadvantages include:

- Faults could affect all connected installations.
- Oil and gas operators will need technical and commercial agreements to plan and operate the shared network.

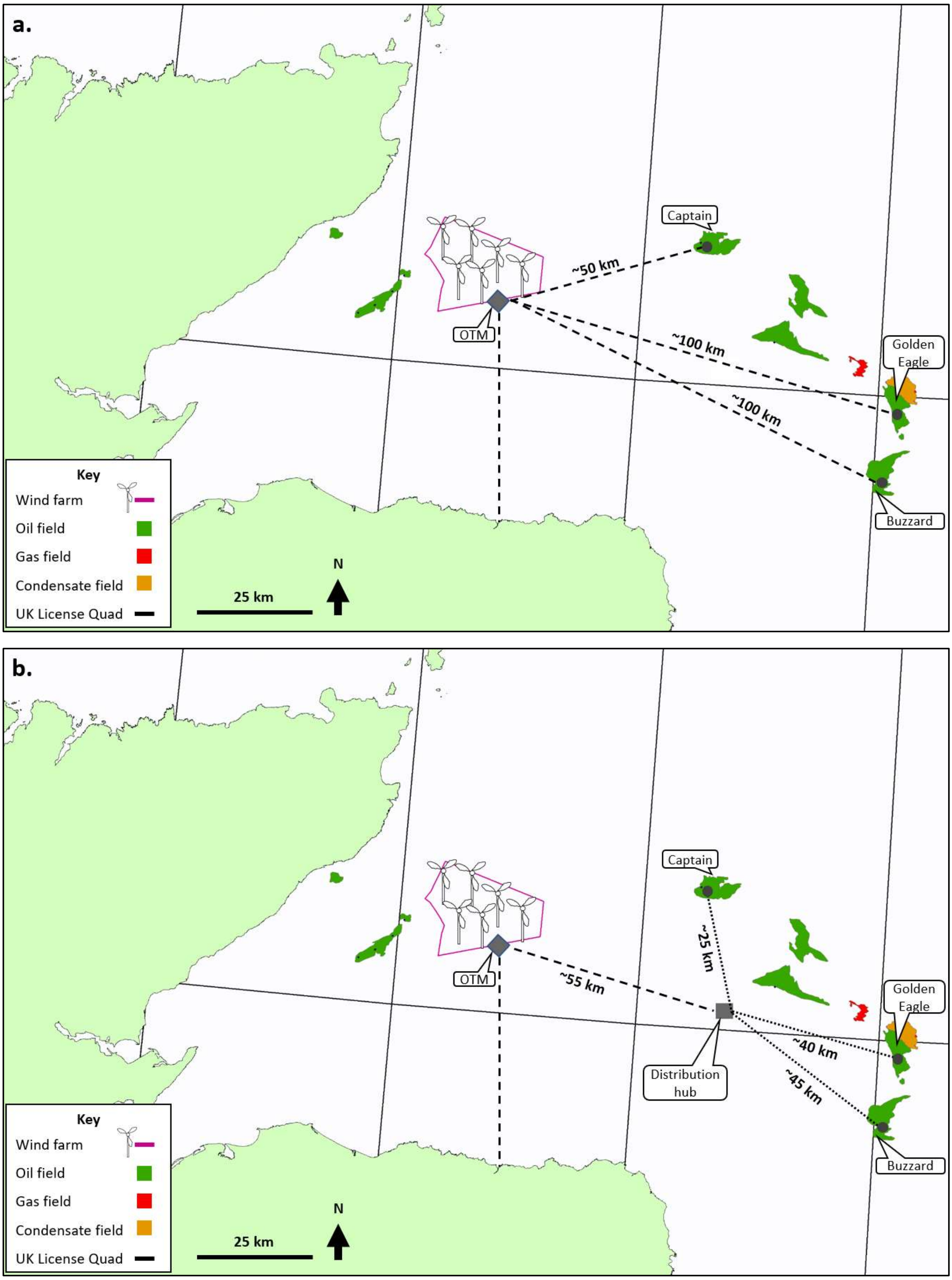


Figure 22: Offshore network layouts for sourcing electricity from Moray East wind farm to Captain, Buzzard and Golden Eagle platforms: a. Each field has its own connection to the wind farm; b. A shared distribution hub would distribute power to the platforms at the required frequency and voltage. Transmission link from OTM to shore is shown on maps.

Power can be transmitted using high-voltage alternating current (HVAC) or high-voltage direct current (HVDC) cables. Electricity from the Moray East OTMs will be transmitted onshore and connected using alternating current (AC) which was reported by the wind farm developers to be less expensive than direct current (DC) [93], [95].

HVAC or HVDC cables could be used for transmitting electricity from the wind farm to the platforms or distribution hub. Based on the power demands of the Captain, Buzzard and Golden Eagle platforms the capacity of the cables would be required to be 120 MW (Section 2.4) but it would be forward thinking to plan for possible future connections and an increased demand in future.

4.1.2 HVAC transmission

HVAC cables are a well-established technology and are commonly used for electricity transmission. However, over long distances they can encounter problems associated with the capacitance and current generated by the cables. Electricity transmission cables are composed of an inner and outer conductor separated by a dielectric (insulator). The conductors can store electric charge between them and hence the cables act as a capacitor. Current through a capacitor is proportional to the rate of change of voltage, $\frac{dV}{dt}$, given by Equation 7 [96]:

$$I = C\frac{dV}{dt} \tag{7}$$

where C is capacitance (Farad, F). In AC systems, the voltage as well as the current varies sinusoidally. The current that flows in the transmission line is the charging current, I_C, given by Equation 8 [97]:

$$I_C = V \times 2\pi \times f \times C \tag{8}$$

where f is frequency (Hertz, Hz). The capacitance is proportional to the area of the capacitor, given by Equation 9 [98]:

$$C = \varepsilon\frac{A}{d} \tag{9}$$

where ε is the permittivity of free space (8.84×10^{-12} F/m), A is the area of the conductors (m^2) and d is the distance between the conductors (m). The area is given by the width multiplied by the length and therefore, as the length of an AC transmission cable increases, the capacitance increases (Equation 9). This in turn increases the charging current (Equation 8), as well as the reactive power generated which could exceed the rating of the cable [91] and cause failure.

4.1.3 HVDC transmission

Under steady-state DC conditions, the capacitance and current described for HVAC cables does not come into play because the frequency is 0 Hz (Equation 7 and Equation 8). As a result, there is theoretically no limit to the distance that DC power can be carried [91]. Furthermore, the losses in HVDC power transmission are less than in HVAC [99]. The relatively long distance to shore (130 km) from the UK Dogger Bank offshore wind farm, and the reduced losses of HVDC compared to HVAC, are reasons that HVDC transmission is being used in that project [100]. HVDC cables are being used to provide power from shore in Norway – the Utsira High Power Hub project will use an HVDC link to transmit power from shore to an offshore hub platform over a distance of 200 km, where a converter will convert DC power to AC for use on the oil and gas fields' platforms [101].

The Moray East OTMs will transmit electricity to shore via HVAC. If HVDC cables were to be used to transmit from the OTMs to the oil and gas platforms or distribution hub, a converter would be required to convert from AC to DC for transmission. A further converter would be required to convert from DC to AC for use on the platforms. The addition of converter stations would mean a greater capital investment required in the electrification project. For both AC and DC transmission, a step-down transformer would be required to lower the voltage from the transmission voltage of 220 kV for use on the platforms.

4.2 Recommendation on electrical infrastructure and network layout

Based on the information presented, the recommended solution proposed by this project is:

- The layout shown in Figure 22b with shared distribution hub;
- HVAC to be used as the mode of transmission from the wind farm to the distribution hub.

The recommended layout has the advantages described in Section 4.1.1. Furthermore, similar models have been put into operation in Norway in the Utsira High Power Hub project and, as such, has been shown to be technically feasible.

The length of cable that would be required in this case, approximately 55 km between the wind farm and the proposed distribution hub, should be suitable for HVAC transmission. There are examples in Norway of submarine HVAC cables from shore to offshore oil and gas installations that are longer than 55 km – the Martin Linge Field receives power from shore via a 55 MW power rated 145 kV cable that is 162 km long [102]. Furthermore, converters would not be required to switch from AC to DC and back again.

4.3 Discussion on electrical infrastructure and network layout

The electrification of the power generation system of offshore oil and gas platforms will be technically and commercially complex. Companies operating in the UKCS are notoriously secretive because of the nature of the commercially sensitive and competitive business environment in which they operate. However, for widespread electrification to become a reality, there will need to be open collaboration between operators. To improve economics, infrastructure could be shared, but this would require operators sharing ideas and technical solutions. This could be partly facilitated by the OGA, but it does not have the same authority as its Norwegian counterpart, the NPD, which is able to be more influential and has mandated that all new petroleum developments should have the possibility of electrification. However, the OGA Strategy does require that operators show commitment to the UK Government's 2050 net zero GHG emissions target, and this is the mechanism by which the OGA can instill change towards electrification and other emissions-saving measures.

An additional challenge is that companies operating in the UK North Sea range from relatively small independents that are fossil fuel focused, to major multinationals that have diversified their businesses to include renewable energy. Investing in an offshore electricity network may be more viable for companies that incorporate offshore renewables projects into their business models. Hydrocarbon focused companies may not have the same longevity as North Sea production continues to decline and fields become uneconomic, or exploration does not add petroleum reserves. Therefore, this type of organisation may be reluctant to invest in electrification if it will not reap the same future benefits as a company with renewables in its portfolio, or companies operating assets with longer field lives.

A potential solution could be that some or all of the electricity infrastructure is funded and maintained by the UK electricity market. The cost of new infrastructure projects in the UK is paid for in part by the consumer through electricity bills. While this may alleviate burden from oil and gas companies, it could be controversial with the electricity consumer, and may not represent value for money if electricity from renewables is being directed to oil and gas platforms owned by companies worth billions of pounds rather than into the electricity grid. This model would also meet opposition from parties who do not believe that the UK oil and gas industry should be provided with enabling technologies to justify continued operation. With the projected growth in offshore wind, large-scale offshore grids could become a reality in future but the timeframe of this is uncertain.

This project focuses on the Moray Firth where operating conditions are not as severe as other areas of the UKCS such as the West of Shetlands (water depth across the Moray Firth is ~100 m). Rosebank and Cambo are two large undeveloped oil and gas discoveries in the West of Shetlands that are located 130 km northwest of the Shetland Islands in water depths of greater than 1000 m [103]. Finding low carbon solutions that can feasibly power these facilities, whether it be by electricity from shore and/or renewables, will be a significant challenge, but one that needs to be addressed if their development is to align with net zero commitments.

5.0 Backup power solutions

Power stability for oil and gas operations is critical and an uninterrupted power supply is essential. It was shown in Section 3.0 that over a monthly timeframe, Moray East could meet the energy demands of the Captain, Buzzard and Golden Eagle platforms. However, wind is an intermittent and unpredictable resource, and as such, a backup supply would be required if wind power was insufficient at a given time. There are no large-scale offshore oil and gas installations that are powered solely by renewables at the time of writing. It has been assumed here that there would be an agreement whereby the electricity demand of the oil and gas platforms would have priority over transmitting electricity from the wind farm to the onshore National Grid.

In this section, three ways by which backup power could be provided will be proposed:

1. Power from pre-existing gas turbines;
2. Power from shore (from the national electricity grid);
3. Power from another offshore wind farm.

Additionally, an energy storage system will be considered.

5.1 Power and energy required from backup solution

In Section 2.4, a combined power demand of 120 MW was reported for the Captain, Golden Eagle and Buzzard platforms. This was subtracted from the calculated total power output of the wind farm and a duration curve was produced, which shows the frequency of occurrence of instances of insufficient wind power output (Figure 23). The power requirement of a backup source to meet the 120 MW demand in these instances (based on the same aforementioned subtraction) is represented in Figure 24. The graph shows that the ~30.0% of time that there is insufficient wind power generated to meet the demand of all platforms occurs randomly throughout the year. The total annual energy required from a backup power solution is approximately 230 GWh (calculated by summing the power required from the backup source to meet demand, which is shown for one third of the year in Figure 24). This is 22% of the total annual 1045 GWh demand of the platforms (reported in Section 2.4), which indicates that Moray East wind farm is able to meet 78% of the platforms' energy demands. This is a greater proportion than in Aardal et al. [20] and He et al. [21] (described in Section 1.4.1), but both used case studies where the capacity of the wind farm is less than the demand. This is unlike the present project where wind farm capacity (950 MW) exceeds the demand (120 MW).

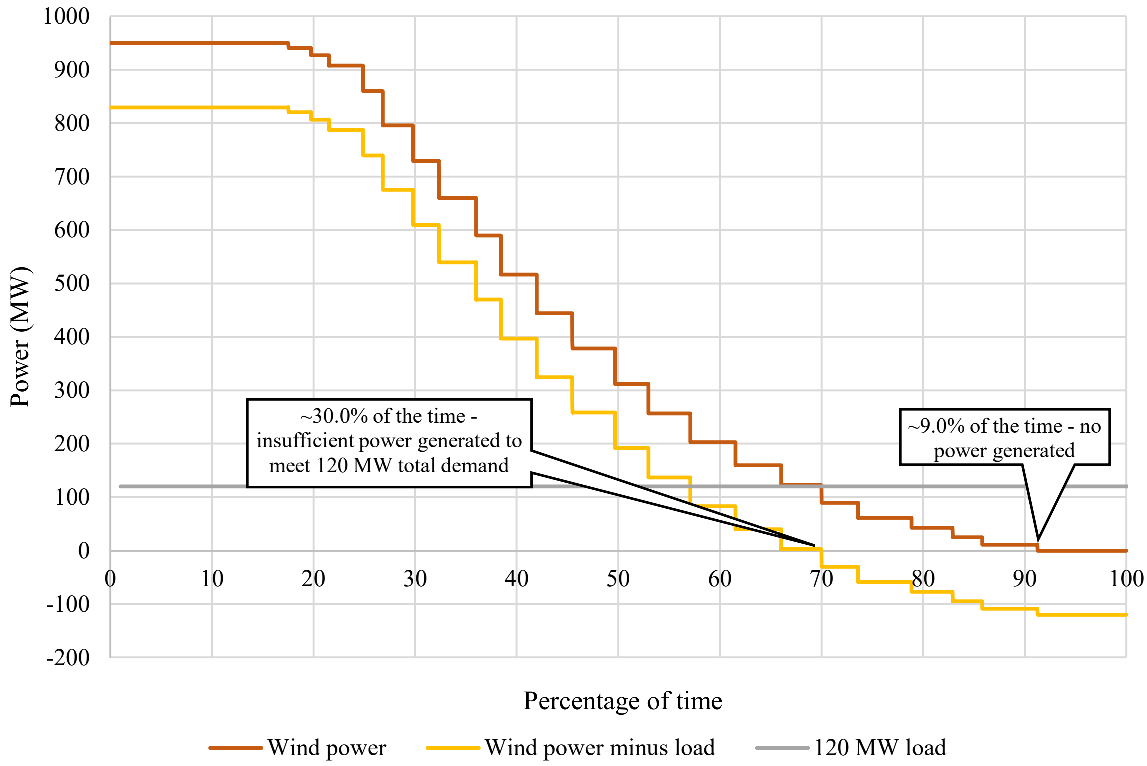


Figure 23: Duration curves of power output from Moray East wind farm (100 turbines) and of wind power minus 120 MW load showing the percentage of time that no power or insufficient power is generated.

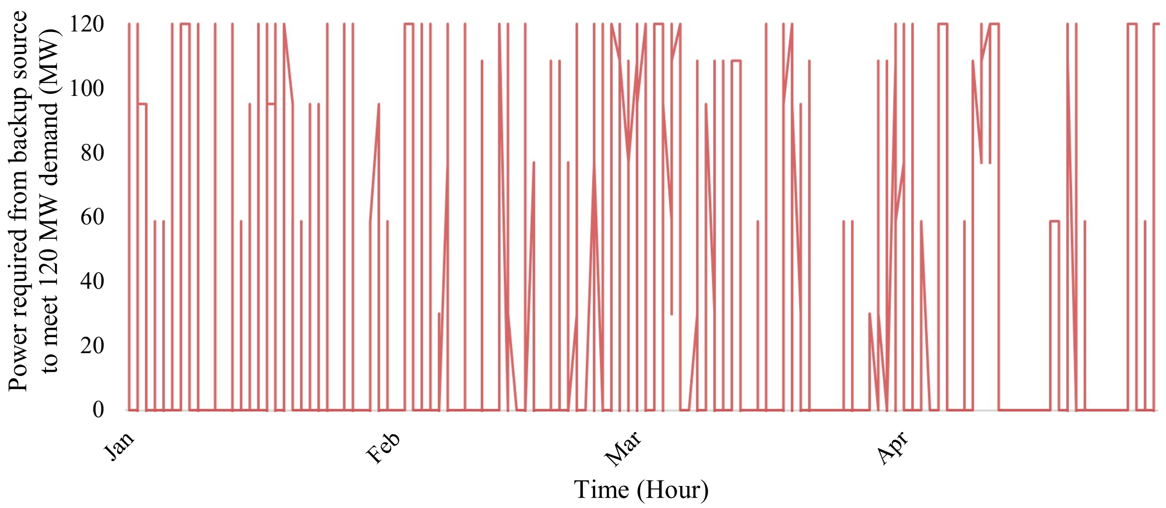


Figure 24: Demand for power to meet 120 MW total demand when there is no or insufficient wind power. January to April is shown as an example of the full year. Total annual energy required is ~230 GWh.

At times there will be enough power generated to meet some but not all of the 120 MW demand, and there will therefore need to be a strategy about how power is shared in such a scenario.

The result shown in Figure 23 and Figure 24 is based on one version of wind data and will be non-unique, but it is reasonable to expect that there will be occurrences of no or insufficient power generation in a given year. It should also be noted that hours with no recorded wind speed were given values of 0 m/s (Section 3.2.1) and so the number of instances of zero or insufficient power could be overestimated.

5.2 Power from pre-existing gas turbines

The gas turbines installed on the platforms could be used when there is insufficient generation from wind. Although gas is a dispatchable fuel source, the turbines will take time to achieve full start-up, which could be in the order of tens of minutes [104]. Figure 24 shows that there are instances when all 120 MW would be required to be met by gas turbines and instances when only part of the 120 MW would be required. An additional consideration to the gas turbine start-up time, is that starting and stopping turbines could cause the machinery to degrade and potentially reduce their lifespan [19]. Furthermore, running gas turbines at levels lower than their rated power is inefficient because their fuel efficiency decreases with decreasing loads (Figure 25).

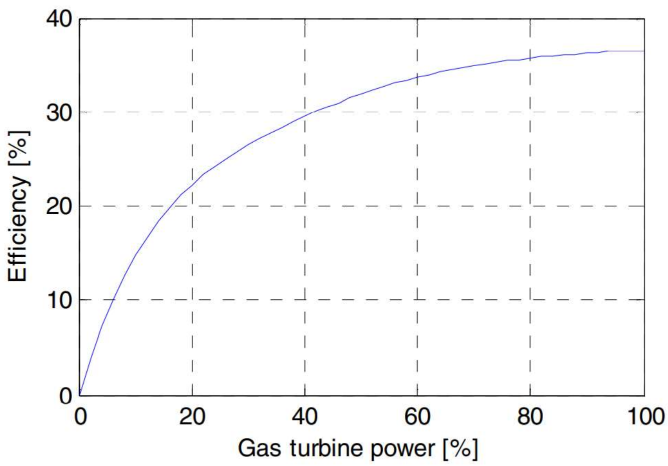


Figure 25: Typical efficiency curve of a gas turbine used on North Sea offshore oil and gas installations showing decreasing fuel efficiency at reduced loads [25].

To minimise this effect, an order of priority for receiving electricity from the wind farm could be assigned. A possible order is from largest demand to smallest, i.e., Buzzard then Golden Eagle then Captain. In this scenario, Buzzard's power demand would be prioritised to be met by output from the wind farm, and any surplus wind power then directed to Golden Eagle. If the wind power is insufficient to meet Golden Eagle's demand, its gas turbines would be employed to make up the shortfall. Then similarly for Golden Eagle to Captain. This scenario was scripted and the duration curve is presented in Figure 26. It shows that when there is demand for gas on Captain and Golden Eagle, it is either at maximum capacity for all (Captain) or the majority (Golden Eagle) of the time. This reduces the inefficiency of the gas turbines operating on Captain and Golden Eagle (Figure 25), although they would still operate in a start-stop manner. A minimum gas turbine run-time could be enforced to reduce the potential impact of mechanical degradation [19].

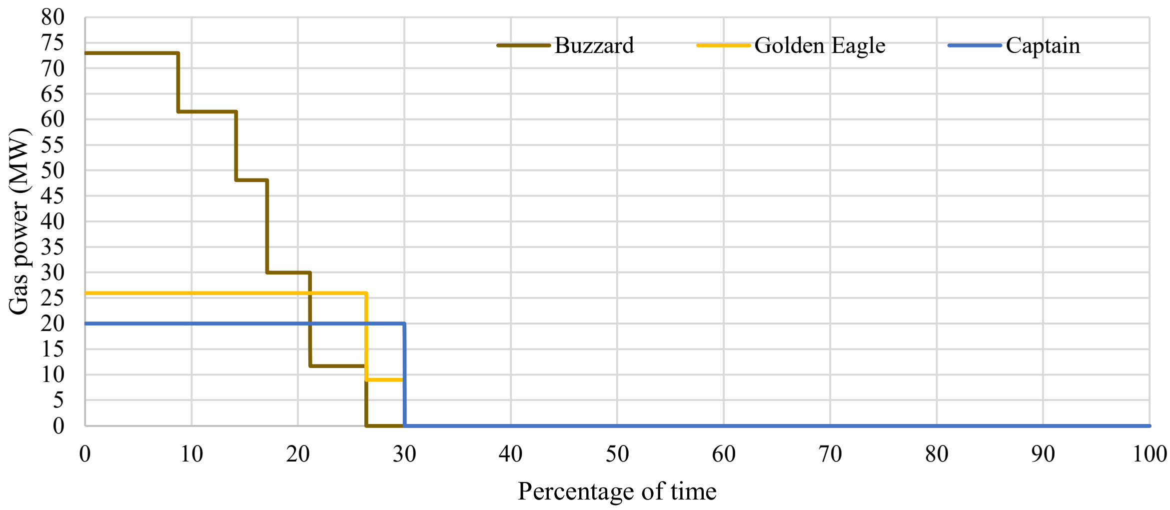


Figure 26: Duration curve of the requirement for gas power on each platform when there is no or insufficient wind power. Power demands are: Buzzard – 73 MW; Golden Eagle – 26 MW; and Captain – 20 MW.

Alternatively, Diesel generators could be used to provide backup power. There are other industries that require electrical power to be supplied quickly in the event of a power cut, such as in healthcare, where lifesaving equipment is being used. The Buzzard and Golden Eagle platforms do not currently use Diesel generators and so would need to be installed. Moreover, since a Diesel generator has a lower power to weight ratio than a gas turbine of the same power, it could be impractical if there are payload constraints offshore. From an environmental standpoint, Diesel fuel emits approximately 37% more CO_2 per kWh compared to natural gas (Section 2.4) and as such might not be accepted by the OGA as an admissible modification to the power generation system.

Gas turbines would be a convenient backup power source because they are already installed on the platforms, but this analysis has shown that their use would be in a start-stop manner which could be detrimental to the operation and lifespan of the machinery. Integrating gas turbines with wind power would reduce the carbon footprint of power generation on the platforms but would not entirely remove it and there would be continued operating expenses for servicing and maintenance.

5.3 Power from shore

The second backup power solution proposed here is power from shore. When there is insufficient power from the wind farm, demand could be met by the onshore National Grid which has different sources of electricity contributing to the overall mix. An analogue to this concept is the electricity system of the Orkney Islands where electricity demand is predominantly met by renewables (of which the majority is onshore wind). Orkney's electricity network is connected to the mainland National Grid via submarine cables which allows surplus electricity from renewables to be exported, and electricity to be imported when demand is greater than renewable supply. A Diesel power station and gas turbine provide power if there is an electrical system outage. This model could be employed for the oil and gas platforms, where electricity can be received from shore during shortages via the OTMs to the distribution hub (Figure 27), i.e., a bidirectional system. Electricity would be received instantaneously when required, in contrast to gas turbines, which have a start-up time. Furthermore, at less than 0.05 $kgCO_2/kWh$ on average[18] [105], the carbon intensity of electricity from Scotland's National Grid is lower per kWh than natural gas which is 0.18282 $kgCO_2/kWh$ [65]. Alternatively, there could be a direct connection from shore to the distribution hub, but from an engineering perspective it would be simpler to co-locate with the pre-planned transmission lines.

The disadvantage of using power from shore as a backup solution is that there is the risk of a power outage or fault in the cabling. Secondary power lines could be installed as partial mitigation, but the risk of a lack of electricity due to a power outage would still exist.

Power from shore as a backup power solution offers many advantages, as described. The concept is also proven in Norway for multiple oil and gas fields. This presents the opportunity for knowledge and experience to be shared cross-border.

[18] Average carbon intensity of the electricity grid in Scotland was 0.024 $kgCO_2/kWh$ in 2017 [105].

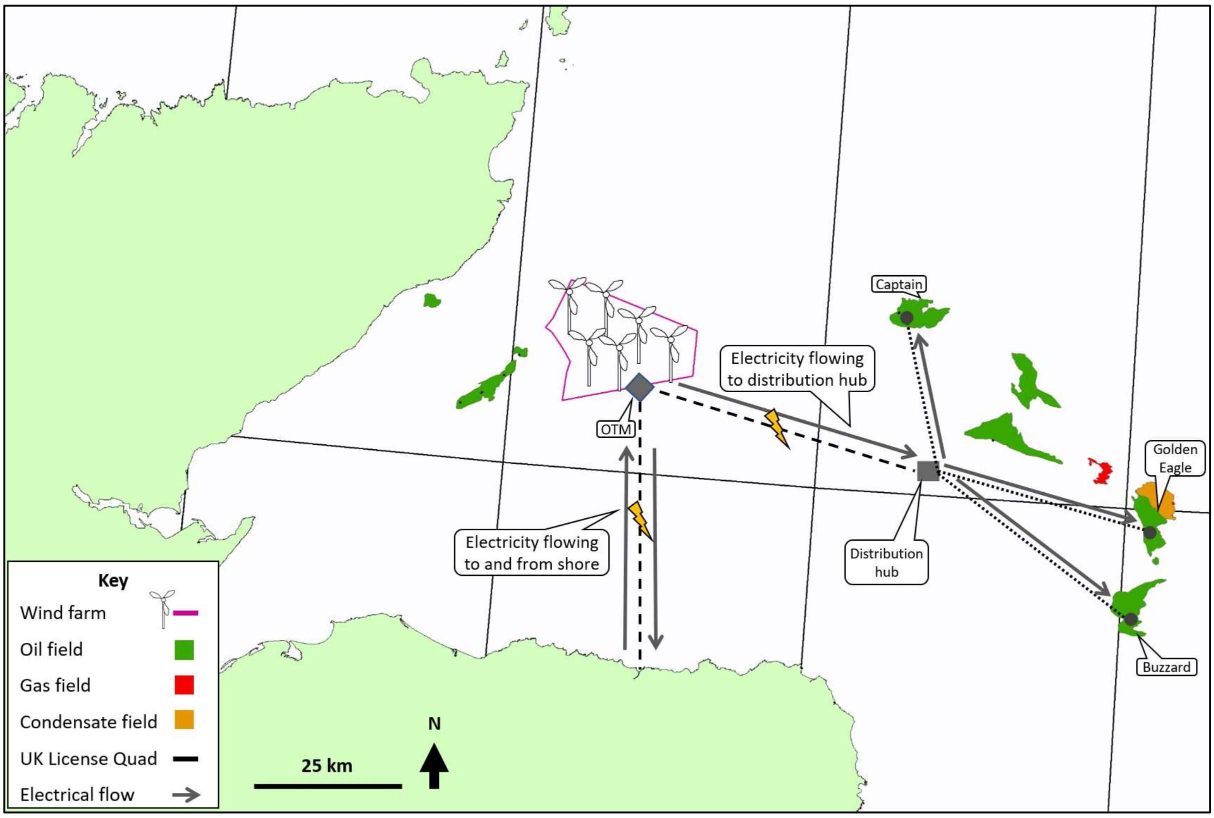


Figure 27: Electricity can be both transmitted and received from shore via the OTMs to ensure continuity of electricity supply to the platforms.

5.4 Power from another offshore wind farm

Another wind farm in relatively close proximity to the platforms could be used to provide backup power. It is expected that the capacity of offshore wind will grow (Section 1.4.1). The sites that will become available through ScotWind Leasing for potential future wind farm projects are shown in Figure 3. However, any future developments that come to fruition will have a long lead time. Backup power from another offshore wind farm would require a second commercial deal to be reached between oil and gas operators and wind farm developers and a separate connection to the distribution hub. Furthermore, another site will also experience intermittency in power output due to variable wind conditions and, given the scale of weather systems, this intermittency is likely to be at least somewhat correlated to Moray East. For these reasons, it is concluded that power from another wind farm would not be a suitable backup solution.

5.5 Cost of backup power

The annual cost to provide the required energy of each backup power solution was calculated, as were annual CO_2 emissions. The cost considers the unit cost of energy sources only (Table 7).

Table 7: Unit cost of energy sources.

Backup power solution	Source	Cost per unit
Power from pre-existing gas turbines	Natural gas	£15/MWh[19] [106]
Power from shore	Electricity from National Grid	£129/MWh[20] [107]
Power from another offshore wind farm	Electricity from offshore wind farm	£41/MWh[21] [108]

As previously stated, the annual energy required to make up for the shortfall in wind farm output was calculated to be about 230 GWh. The annual cost and CO_2 emissions results are shown in Figure 28 and were calculated as follows.

Power from pre-existing gas turbines:

- Only the gas power demands of Buzzard and Golden Eagle were considered when calculating the annual fuel cost (fuel gas for Captain is sourced from production at the field).
- Annual gas demand of 230 GWh was converted to an annual gas consumption assuming a 30% turbine efficiency as discussed in Section 2.4.
- Annual cost of natural gas consumption was calculated using the wholesale gas price of £15/MWh (Table 7)[22].
- Annual CO_2 emissions includes emissions from Captain, Buzzard and Golden Eagle platforms and the prioritisation strategy described in Section 5.2. A natural gas carbon intensity of 0.18282 $kgCO_2/kWh$ was used [65].

[19] Wholesale gas price: the price of fuels purchased by non-domestic consumers in the UK. The average over 2020 for very large consumers was used for the calculation (1.48 p/kWh = £15/MWh).
[20] Average unit price of electricity for large business in 2021.
[21] Offshore wind power price is the average strike price of offshore wind in the latest CfD round.
[22] Operators may have fixed gas price contracts but this is unknown and therefore wholesale gas price has been used.

Power from shore:

- Annual cost of electricity was calculated using a price of £129/MWh (Table 7) for annual demand of 230 GWh.
- Annual CO_2 emissions were calculated assuming that the carbon intensity of electricity from the National Grid is 0.05 $kgCO_2/kWh$ [105].

Power from another wind farm:

- Annual cost of electricity was calculated using a price of £41/MWh (Table 7) for annual demand of 230 GWh.
- Annual CO_2 emissions are zero because wind power emits no CO_2 at the point of use.

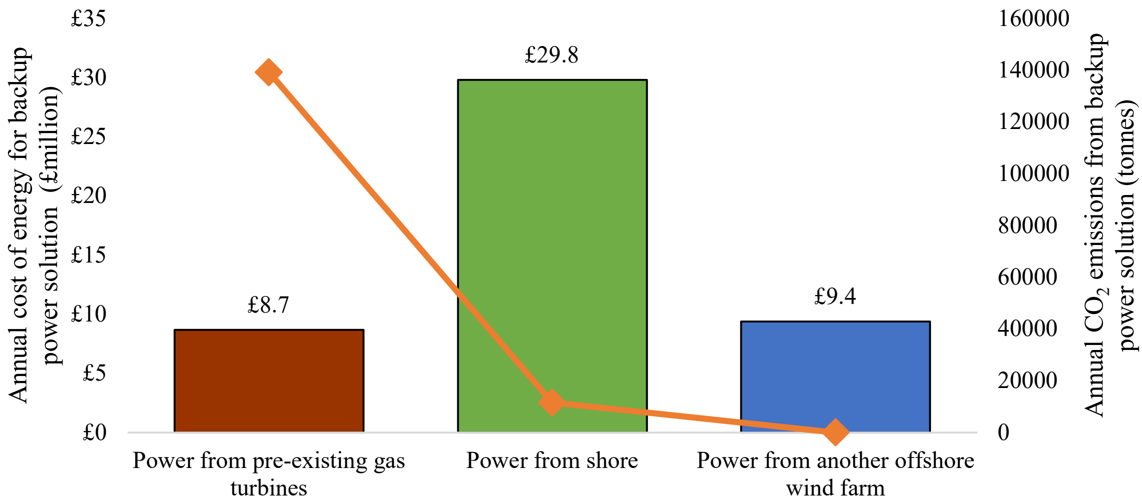


Figure 28: Comparison of total annual cost (columns; based on unit cost of energy only) and CO_2 emissions (squares) of backup power solutions. Annual emissions from the use of natural gas in the current power generation system is ~611,000 tonnes CO_2 (Table 1).

Figure 28 shows that, based on the unit cost of energy sources, power from shore is the most expensive backup power solution. The UK electricity price includes policy tariffs such as climate change levies and renewables obligation [3] which is in part the reason for the difference in cost between power from shore and another offshore wind farm. Natural gas is the lowest cost solution, although it should be noted that if Captain was also to import fuel gas, the annual cost would increase to £11.3m. However, annual CO_2 emissions from natural gas would be twelve times higher than power from shore. Implementing power from shore as the backup solution would result in emissions savings of over 600,000 tonnes CO_2 annually[23].

[23] Calculated by subtracting the emissions from power from shore in Figure 28 from the natural gas emissions presented in Table 1.

An additional consideration is changes in levies and carbon tax or participation in an Emissions Trading Scheme (ETS) which could increase operating expenditure. Carbon tax has already influenced development decisions in Norway. This is due to the country planning to increase the tax on a tonne of CO_2 emitted from €60 to €200 (£50 to £170) by 2030 [109], making electrification more economically viable in some cases than fossil fuel alternatives. For the scenario where backup power is provided by existing gas turbines, the carbon tax that could be incurred at £50 per tonne would be ~£7.0m, or ~£23.7m at £170 per tonne[24]. £50 per tonne was the opening price of the UK's ETS in May 2021 [110] which could apply to the upstream oil and gas sector in future [111].

5.6 Energy storage

As an alternative to the backup power solutions already described, energy storage in batteries could be considered. Batteries could be charged when there is sufficient surplus power available and discharged when required. They have the advantage of being able to achieve high round-trip efficiencies (greater than 90%) and emit no GHGs at the point of use, however their performance degrades with time and use.

State-of-the-art utility-scale high-density modular 'Megapack' batteries have been developed by Tesla which can be deployed in capacities up to 250 MW [112], therefore the technology is available to provide the magnitude of battery capacity required for the platforms. However, at 250 MW the Megapack's usable energy capacity is 1 GWh. This would give a storage duration – the amount of time the battery can discharge at its power capacity before its energy capacity is depleted – of four hours, and so could not be utilised to provide power over long timescales, but could have a role in providing power while gas turbines start up. Load shedding could be used in emergencies where any load that is deemed non-essential is switched off to prioritise essential operations.

Although technically possible, the practicalities of deploying batteries offshore at the full capacity required is likely to make it infeasible. The 250 MW Megapack described above has a footprint of 12,141 m^2 so 120 MW could have a footprint of around half of that, which at 6070 m^2, is more than three quarters of the area of a typical football pitch and may require a platform of its own to accommodate it. Furthermore, the negative environmental impact that mining the finite rare earth elements required for batteries has been documented. The mining process is both water and CO_2 intensive [113], [114] and has also resulted in negative social

[24] Calculated using the annual CO_2 emissions from power from pre-existing gas turbines shown in Figure 28.

impacts [115]. Reliance on ever increasing battery capacity could therefore be considered unsustainable. For these reasons, deployment of batteries is not being recommended by this project.

5.7 Discussion on backup power solutions

To align with net zero targets and achieve a meaningful reduction in GHG emissions, operators should seek to decarbonise the power generation system of oil and gas installations as far as possible, while ensuring that power demand can be met. Considering the analysis presented in this section, receiving backup power from shore, or from another wind farm when there is insufficient supply from Moray East, would be most in line with the OGA Strategy. Although the cost of electricity from another wind farm is less expensive than from shore, the challenge of intermittency would still be present. For this reason, power from shore is recommended as the backup power solution to an electrified power generation system with wind as the primary source of power. The infrastructure to receive power from shore should be co-located with already proposed transmission lines.

It has been shown that Moray East offshore wind farm could capable of meeting 78% of the platforms' energy demands, and can therefore act as the primary source of power. The next section will present the second renewable energy source studied in this project: geothermal.

6.0 Geothermal energy

This section will introduce geothermal energy and its application to the offshore oil and gas industry. The methodology and results of the calculation of thermal and electrical power output from Captain, Buzzard and Golden Eagle geothermal fluids will be presented.

6.1 Introduction to geothermal energy

Geothermal energy is traditionally associated with tectonic plate boundaries and areas of volcanic activity. These are usually high enthalpy[25] sites where the geothermal gradient is above average [116] due to the high temperatures from the Earth's core. Geothermal fluid can be in the liquid state under high-pressure, or steam between typical temperature ranges of 250°C to 300°C [117]. Figure 29 shows a map of the major tectonic plate boundaries – USA, Indonesia, Philippines, Turkey and New Zealand make up the '1 GW Country Club' that have more than 1 GW_e[26] of installed geothermal capacity[27], and are all intersected by plate boundaries. USA and Indonesia have more than 3 GW_e and 2 GW_e of installed capacity, respectively [118]. The three main uses of geothermal energy are [119]:

- Power plants using hot water or steam to generate electricity;
- Direct heat use and district heating;
- Heat pumps.

In power plants, geothermal steam can be used directly, high-pressure geothermal liquid can be vaporised, or the high-pressure liquid can transfer its heat to vaporise another working fluid. In all cases, the steam is processed by a turbine which is connected to an electricity generator. Direct heat can be used in agricultural and industrial processes or for district heating. Ground source heat pumps transfer heat from the ground to provide heating and cooling to buildings.

Energy from geothermal resources is less carbon intensive than fossil fuels[28], and is predictable, making it a suitable baseload energy source. This is in contrast to climate-based renewable energies which are intermittent. However, high enthalpy sites described here are geographically

[25] Enthalpy (h) is the sum of the internal energy (E_{int}) and the product of pressure (p) and volume (V) of a thermodynamic system, $h = E_{int} + pV$ [135].
[26] Gigawatt electric.
[27] Correct at year-end 2019.
[28] Some geothermal operations result in GHG emissions (predominantly CO_2) [151].

limited and, in this regard, attention is turned to low enthalpy heat sources in intraplate settings such as the UK.

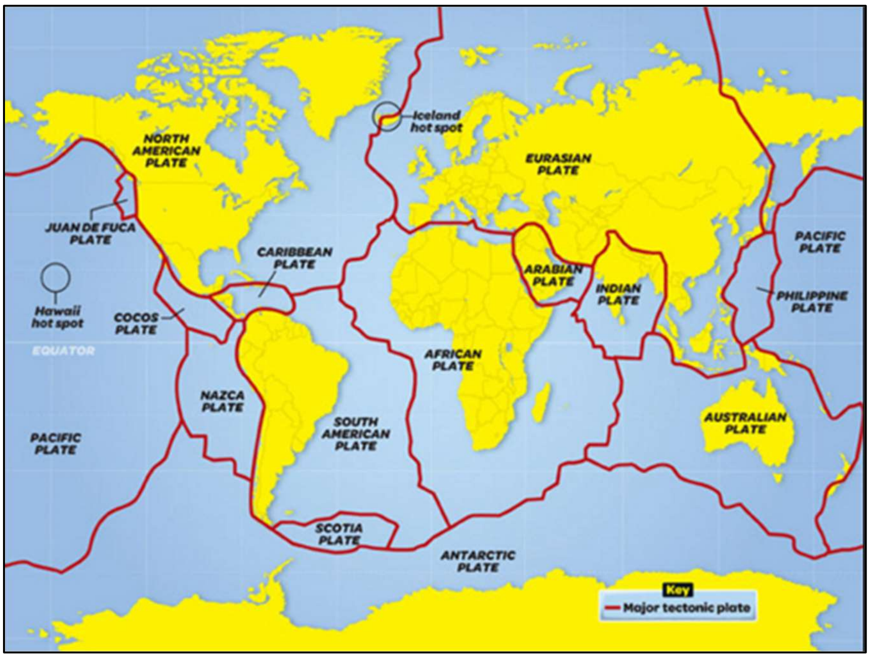


Figure 29: Map of major tectonic plate boundaries [120].

6.2 Low enthalpy heat sources

Low enthalpy sites, or those with low-grade heat sources, are characterised by temperatures below approximately 150°C [121], and can be used for district heating. Iceland is a leader in geothermal district heating – almost 90% of the hot water and heating supplied to its buildings is from geothermal resources [122]. Successive generations of district heating have had decreasing supply temperatures and the most recent 4th Generation aims to recover heat from water at temperatures of 30°C to 70°C [123]. It is not only geothermal resources that can provide heat for this purpose. There is a vast amount of waste heat released as a by-product of industrial processes that could be utilised for district heating. Electricity can also be generated from lower temperature heat sources, which will be the focus of Section 6.5. In the UK offshore oil and gas industry, significant quantities of water are produced at temperatures high enough for the applications described here.

6.3 Water production in the offshore oil and gas industry

Within the reservoir rock of an oil and gas field, hydrocarbons occupy part of the pore space[29] while the rest is occupied by water, or brine. Captain, for example, has an average hydrocarbon saturation across the field of 87%, and an average water saturation of 13% [52]. Fields usually

[29] The space between the grains of the reservoir rock which is occupied by fluids.

have a hydrocarbon-water contact and below the contact, the pore space of the rock is 100% water saturated. At a point in time after production begins, there will be water breakthrough resulting in water being coproduced with the hydrocarbons. The timing of the breakthrough varies by field. The produced water is separated from the hydrocarbons and will have impurities, requiring it to be treated before disposal offshore. With continued production of water from the reservoir, the pressure within the field declines. To provide pressure support and improve hydrocarbon recovery, fields are commonly injected with sea water [9].

Over time, as the oil and/or gas resource becomes depleted due to continued extraction, the quantity of hydrocarbons produced will decrease and water production will increase. An example for Captain is shown in Figure 30 where historical oil production and water cut[30] are displayed. The increase in water produced over the history of field development is clearly observed, with the field now producing significantly more water than oil. On average, UK fields produce more than 2.5 times more water than hydrocarbons, and can be up to twenty-five times more in certain cases [124], so the resource is abundant.

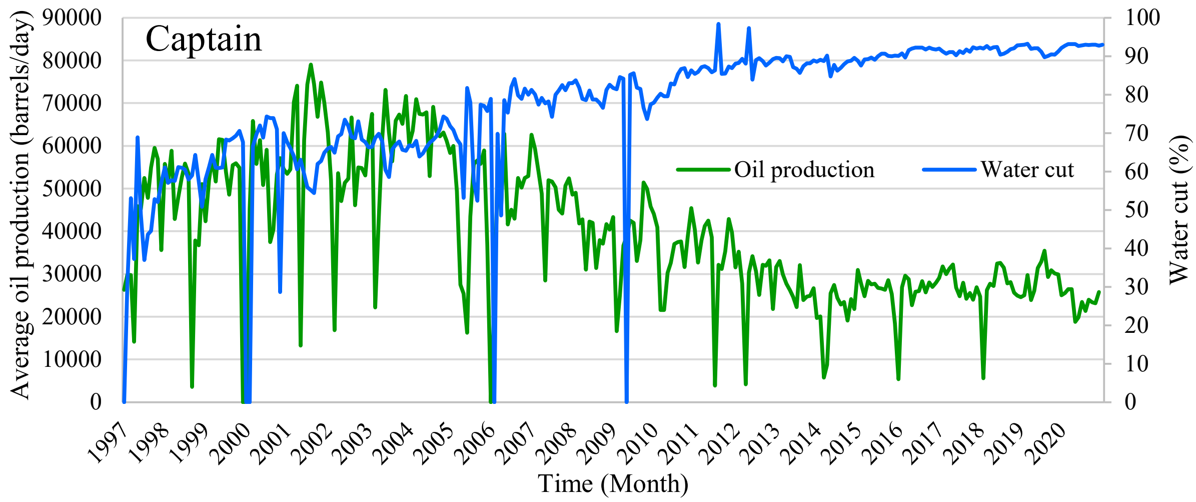


Figure 30: Captain Field average oil production and water cut from beginning of field life to present. Large excursions are due to maintenance shutdowns. Data sourced from the OGA Petroleum Production Reporting System [125].

6.4 Thermal power output

The temperature of coproduced water from UK North Sea oil and gas fields can be considered a low enthalpy heat source. This is particularly relevant in fields where the reservoir is deeper because of the increase in temperature with depth due to the geothermal gradient. Reservoir depth varies considerably between North Sea fields. Most are deeper than 1 km below the

[30] The water cut is the percentage of water produced. 90% water cut represents 90% water and 10% oil produced in a given volume.

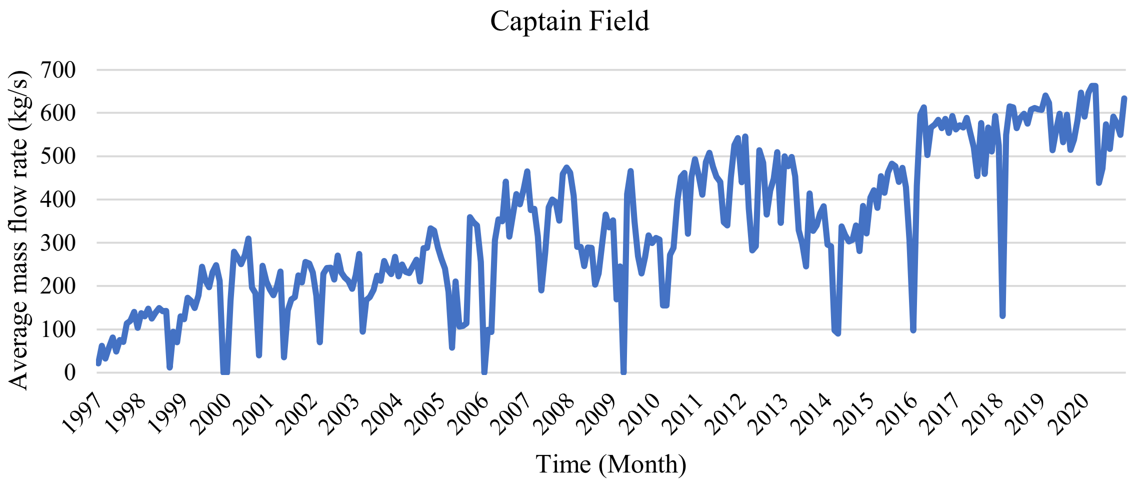
seabed and some are in excess of 5 km. For any given reservoir depth, temperature can vary laterally due to differences in local heat flow.

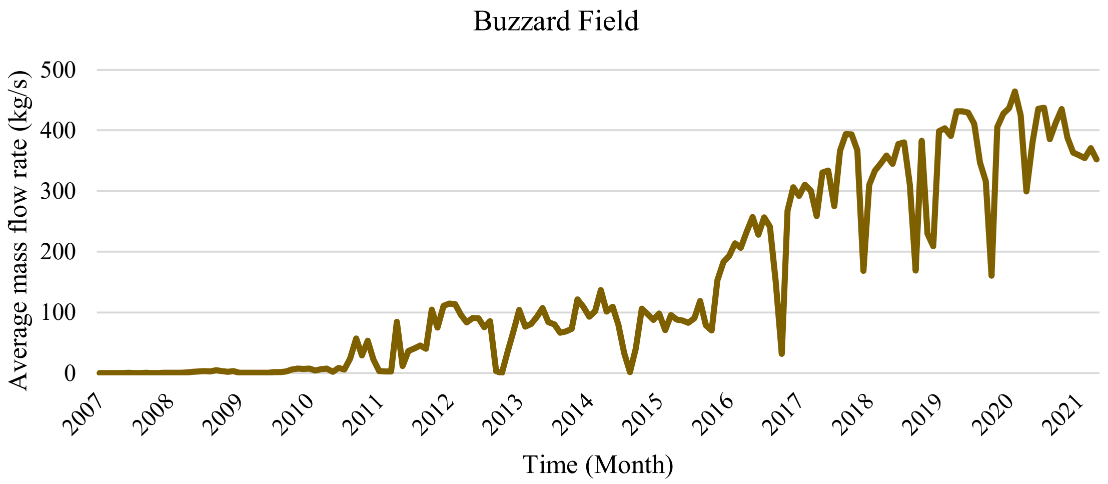
6.4.1 Calculation of theoretical thermal power output

The theoretical thermal power output, Q, of produced water from Captain, Buzzard and Golden Eagle was calculated following the methodology presented by Watson, et al. [126] and Equation 10:

$$Q = \dot{m} \times c_p \times \Delta T \tag{10}$$

where $\dot{m}$ is the brine mass flow rate (kg/s), c_p is the brine heat capacity (J/kg.K) and ΔT is the difference between the source temperature (T_S, °C) and the ambient temperature (T_A, °C). Mass flow rates in kg/s were calculated from average monthly water production data published by the OGA [125]. The mass flow rates for Captain, Buzzard and Golden Eagle over field life are shown in Figure 31 and are high, demonstrating the potential for large power output based on Equation 10. The trend for Captain shows a gradual increase in mass flow rate, while Buzzard shows a peak in 2020 then an overall decrease until the present. The trend for Golden Eagle shows a relative plateau since 2019, but variability is still observed. These variations were taken into account when calculating thermal power output but the large excursions observed in the graphs in Figure 31 were neglected.





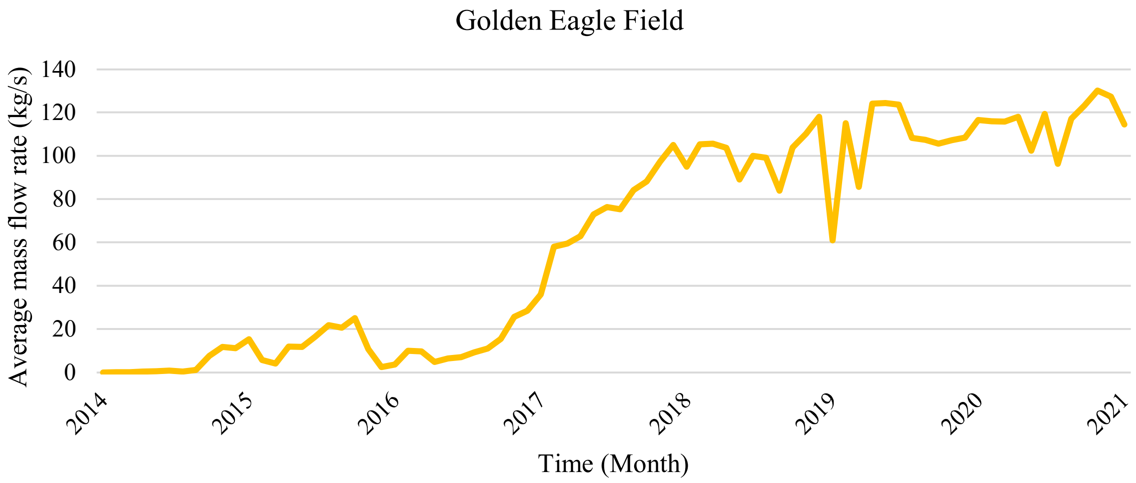


Figure 31: Average brine mass flow rate per month for Captain, Buzzard and Golden Eagle. Note that the y-axes are on different scales. Data sourced from [125].

Standard relationships between water temperature, salinity and density, and between water density and heat capacity [127], [128], were used to estimate the heat capacity of the coproduced brine. Salinities were obtained from the literature and are 15,000, 64,900 and 69,000 ppm NaCl for Captain, Buzzard and Golden Eagle, respectively [52], [56], [60]. For these salinities, the heat capacity is 4150 J/kg.K for Captain, 4100 J/kg.K for Buzzard and 3720 J/kg.K for Golden Eagle.

Source temperatures were obtained from literature and are 31°C, 85°C to 95°C and 170°C for Captain, Buzzard and Golden Eagle, respectively [52], [56], [60]. Air temperature in this part of the North Sea is between 0 and 19°C [76]. Ambient temperature of 10°C has been used to provide a comparison between the three fields. Theoretical thermal power outputs – calculated using Equation 10 – for each field are shown in Table 8. These are maximum cases because T_A has been set to 10°C rather than the temperature of a specific end use.

Table 8: Calculated theoretical thermal power output in megawatt thermal (MW_{th}). ΔT is the difference between source and ambient temperatures. Minimum and maximum are the result of the range in mass flow rates.

Field	ΔT	Thermal power output (MW_{th})		
		Maximum	Minimum	Average
Captain	21	58	38	48
Buzzard	85	162	123	142
Golden Eagle	160	77	36	57

6.4.2 Comparison with published results

The calculated thermal power outputs were compared with published results for Northern North Sea fields (locations shown in Appendix B). A study by Watson et al. [126] estimated thermal power output of Ninian, Statfjord and Brent based on mass flow rates reported by Auld et al. [9] – shown in Table 9. The mass flow rates of Ninian, Statfjord and Brent are an order of magnitude greater than those of Captain, Buzzard and Golden Eagle displayed in Figure 31. The temperature differences are of the same order of magnitude as Captain and Buzzard but ΔT for Golden Eagle is a higher order of magnitude. Taking into account the difference in mass flow rates (c.f. Figure 31 and Table 9), the thermal power output results presented in Table 8 are in line with those from literature shown in Table 9.

Table 9: Thermal power output reported in literature for Ninian, Statfjord and Brent fields [9], [126].

Field	$\dot{m}$ (kg/s)	T_S (°C)	T_A (°C)	ΔT	Thermal power output (MW_{th})
Ninian	1231.1	102	5	97	394
Statfjord	1417.43	89	5	84	393
Brent	1096.62	96	5	91	329

The thermal power outputs presented here, and found literature for other North Sea fields, are significant. However, the thermal power is likely to be greater than required on Captain, Buzzard and Golden Eagle, even in the minimum cases shown in Table 8. This conclusion is based on data for the UK Cambo Field situated West of Shetlands which is expected to have a peak heat demand of 20 MW [3] but will experience more harsh operating conditions (including colder temperatures) than the fields considered here.

6.4.3 Exporting geothermal fluids onshore

It has been proposed by authors including Kurnia et al. [129] and Bu et al. [130] that the offshore oil and gas industry could be repurposed using existing infrastructure to utilise geothermal energy. Fluids produced through oil and gas production could be used directly for a variety of purposes including heating. The low-grade heat of the brine produced from Buzzard and Golden Eagle, at temperatures of 95°C and 170°C, respectively could be considered for space heating. It would not be suitable for direct use as hot water because the produced brine is highly saline and will still contain impurities even after separation from the oil [126].

The challenge with the transport of hot fluids is the heat loss that will occur as they are transported through submarine pipelines. Major North Sea pipelines are the Forties Pipeline System, an oil and gas transportation network, and the Frigg UK Pipeline, a natural gas transportation network. The Frigg Pipeline serves both Buzzard and Captain. It has therefore been used as the basis for calculating heat loss to determine if it would be feasible for use in transporting coproduced hot water instead of natural gas in the future. The pipeline is 32 inches (0.8128 m) in diameter with ¾ inch (0.01905 m) steel walls reinforced with concrete [131] and has been modelled as shown in Figure 32. Heat loss in the pipe will occur by conduction and forced convection. For conduction, it is assumed that the inner and outer surfaces are uniform and therefore heat flow is only in the radial direction.

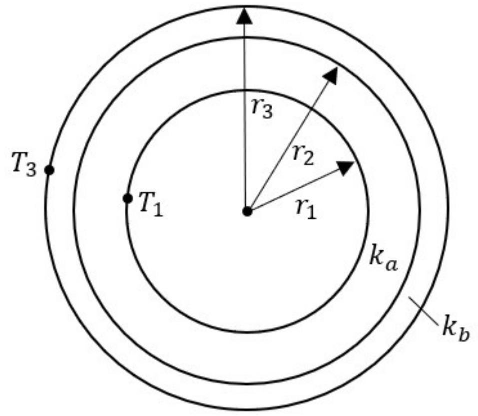


Figure 32: Cross sectional schematic of the Frigg UK Pipeline (not to scale). Layer a – concrete, layer b – steel.

The heat transfer by conduction, Q_{COND}, is defined by Equation 11 [132]:

$$Q_{COND} = \frac{T_1 - T_3}{\sum R} \tag{11}$$

where the thermal resistance, R (K/W), of each layer of the pipe is given by Equation 12 [132]:

$$R = \frac{\ln\frac{r_o}{r_i}}{2\pi k L} \tag{12}$$

where r_o and r_i are the outside and inside radius of each layer (m), k is the thermal conductivity (W/m.K) and L is the length of the pipe (m). The brine temperature from Buzzard has been assumed for T_1 (95°C) because at 31°C the temperature of brine from Captain is too low to be transported (Golden Eagle not considered as it is not served by the Frigg Pipeline). T_3 is assumed to be 10°C which is the mean sea surface temperature at Wick, UK [133] (Appendix C). Water temperature decreases with depth in the water column but it is deemed suitable to assume 10°C given the other assumptions made. Values for the parameters shown in Figure 32 are given in Table 10.

Table 10: Values for the parameters in Figure 32.

Parameter	Value
r_1 (m)	0.33655
r_2 (m)	0.38735
r_3 (m)	0.4064
k_a (W/m.K)	0.8
k_b (W/m.K)	45
T_1 (°C)	95
T_3 (°C)	10

Thermal resistances for the concrete and steel layers are calculated to be 2.797×10^{-2} K/W and 1.698×10^{-4} K/W, respectively. The thermal resistance of the concrete is greater than steel because its thermal conductivity is lower. The conductive heat transfer per unit length of pipe is found to be approximately 3000 W/m. The direct distance from Buzzard to shore is approximately 58 km, but the true distance of the pipeline is greater. The heat transfer over 58 km is 174 MW which is greater than the maximum thermal power calculated for Buzzard, 162 MW_{th} (Table 8). This indicates that the Frigg Pipeline is not suitable for the transport of hot fluid due to the anticipated conductive heat losses.

The fluid flowing in the pipe would also be subject to heat transfer by forced convection. The magnitude of the Reynolds number, Re, defines if the flow is laminar or turbulent [132]:

$$Re = \frac{\rho u l}{\mu} \tag{13}$$

where u is the fluid velocity (m/s), l is the critical dimension (inner diameter of the pipe, measured in metres) and μ is the dynamic viscosity of the fluid (kg/m.s). The typical fluid velocity of water in a steel pipe is 0.9 m/s to 2.4 m/s [134]. Assuming water properties for the brine at 95°C, the density and dynamic viscosity from property tables are 961.5 kg/m^3 and 0.297×10^{-3} kg/m.s, respectively. The inner diameter of the pipe is 0.6731 m. These parameters give a range of 1.96×10^6 to 5.23×10^6 for Re, which indicates turbulent flow because Re is greater than 4000. This shows that significant heat loss by convection would be expected.

For brevity, the heat transfer by convection has not been presented because the result for conduction already shows that the Frigg Pipeline would not be suitable for transporting and maintaining the temperature of the geothermal fluid. It would require retrofit to insulate it to a suitable degree or a separate dedicated pipeline to transport the hot fluid, both of which would be a significant engineering and financial undertaking and not economically viable. There are, however, potential other uses for the coproduced brine.

6.5 Organic Rankine cycles

The Lindal diagram in Figure 33 shows potential applications for geothermal fluids based on their temperature. It can be seen that the temperature of the brine produced from Buzzard at 95°C would be suitable for electricity generation in an organic Rankine cycle (ORC), which could be a means to supply power from a renewable source to the Buzzard platforms. As described previously, this could form an ideal baseload.

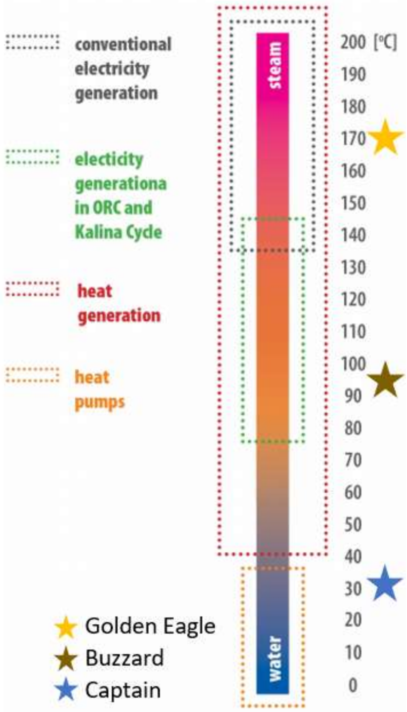


Figure 33: Lindal diagram showing potential applications for geothermal fluids based on their temperature. Temperature of coproduced brine from Captain, Buzzard and Golden Eagle is annotated. Modified after [126].

ORCs follow the same working principle as a conventional steam Rankine cycle, represented in its simplest form in Figure 34, with the main components being heat exchanger (also referred to as the boiler or vaporiser), turbine, condenser and pump. In the steam cycle, water is the working fluid which has a boiling point of 100°C or 373.15 K at atmospheric pressure. The Carnot efficiency, η_C (Equation 14, [135]), gives the maximum theoretical thermal efficiency of a thermodynamic cycle system and shows that the efficiency increases with the input temperature:

$$\eta_C = 1 - \frac{T_C}{T_H} \tag{14}$$

where T_C and T_H are the temperatures of the cold and hot sources, respectively (measured in Kelvin). To maximise thermal efficiency of the Rankine cycle, steam is supplied at high temperatures of several hundreds of degrees Celsius in a power plant.

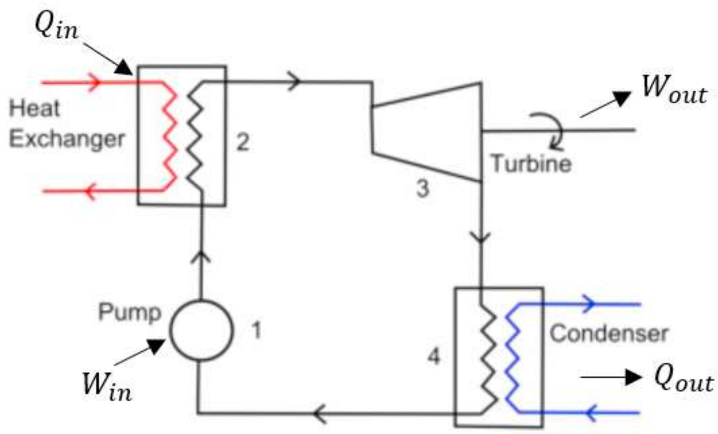


Figure 34: Schematic of the Rankine cycle. Q – heat; W – work. Modified after [9].

To exploit low temperature heat resources, the ORC uses an organic working fluid instead of water. Organic fluids, such as refrigerants and hydrocarbons, have lower boiling points than water, thus requiring less thermal energy for vaporisation [9]. The ORC operates in a closed cycle with four key stages. Referring to Figure 34, the stages are:

- High pressure fluid is boiled and vaporised by transferring heat from a hot source in an isobaric process through a heat exchanger until it reaches its saturation temperature (point 2);
- The saturated vapour is expanded through a turbine to produce mechanical work from the turbine, after which its temperature and pressure drops (point 3);
- A cooling source condenses the working fluid into saturated liquid in an isobaric process and heat is rejected to the environment (point 4);
- The working fluid is repressurised using a pump to be fed back into the heat exchanger (point 1).

A generator connected to the turbine converts the mechanical energy into electrical energy. Many applications of ORCs are described in literature including biomass combined heat and power, solar power plants, waste heat recovery, and, relevant to the present project, geothermal energy [136].

6.5.1 Application to the offshore oil and gas industry

As an alternative to using coproduced brine for heating, as explored in Section 6.4, it could be used to transfer heat to the working fluid of an ORC in its heat exchanger and generate electricity. Based on Figure 33, the brine produced from Buzzard at a maximum temperature of 95°C is most suitable for this purpose. Equation 14 shows that maximising the temperature of the hot source is important for thermal efficiency, but also that a greater difference between hot and cold temperatures will improve thermal efficiency. In this regard, the water of the North Sea provides the ideal condenser cold source at approximately 10°C (Appendix C).

6.5.2 Working fluid selection

The selection of working fluid for an ORC depends on several factors [137], [138], including:

- Thermodynamic and chemical properties
    - The critical temperature, T_{crit}, should be above the highest temperature of the proposed cycle[31].
    - The cold source temperature has to be below the condensing temperature of the fluid for condensation to occur.
    - The freezing point of the fluid should be below the lowest operating temperature in the cycle.
    - The fluid should be chemically stable over the temperature range of the application.
- Environmental
    - Global warming potential (GWP).
    - Ozone depletion potential (ODP).
    - Atmospheric lifetime (the time that fluids remain in the atmosphere).
- Safety
    - It is desirable for the fluid to have low toxicity, low flammability and low explosiveness.

Properties of five working fluids reported in literature that are used commonly in low temperature ORCs are given in Table 11 [121]. The ASHRAE (American Society of Heating, Refrigerating and Air-Conditioning Engineers) safety group classifications are shown in Figure 35.

[31] There are supercritical cycles but operating at high pressures could cause difficulty and have safety implications [140] so they are not considered here.

Table 11: Properties of ORC working fluids. P_{crit} – critical pressure. R indicates a refrigerant. [137], [139], [140].

Working fluid	T_{crit} (°C)	P_{crit} (bar)	ASHRAE safety group	Atmospheric lifetime (Year)	GWP	ODP
R134a	101.06	40.6	A1	13.4	1370	0
R245fa	154.05	36.4	B1	7.6	1030	0
R32	78.11	57.8	A2L	5.2	716	0
Propane	96.68	42.5	A3	0.041	~20	0
Butane	151.98	38	A3	0.018	~20	0

Higher Flammability	A3	B3
Lower Flammability	A2	B2
No Flame Propagation	A1	B1
	Lower Toxicity	Higher Toxicity

Figure 35: ASHRAE Standard 34 Safety Group Classifications. Modified after [141].

In the application considered here, the maximum hot (evaporating) temperature is 95°C and the cold (condensing) temperature is 10°C. R32 and propane would therefore be unsuitable working fluids as their critical temperatures are either lower than or close to 95°C. Of the remaining, butane has the highest flammability but lowest atmospheric lifetime and GWP. R245fa has a lower atmospheric lifetime and GWP than R134a but a higher toxicity. On the basis of suitable thermodynamic and safety properties, R134a will be taken forward for subsequent calculations. In practical terms, the choice of working fluid would be partly driven by cost.

6.5.3 Electrical power output

The rate of work developed through the turbine, W_t (kJ/s), is given by [135]:

$$W_t = \dot{m}(h_2 - h_3) \tag{15}$$

where $\dot{m}$ is the mass flow rate of the working fluid (kg/s) and h_2 and h_3 are the specific enthalpies at points 2 and 3 of the cycle shown in Figure 34 (kJ/kg). To bring the working fluid to a temperature of 95°C, the required mass flow rate of the working fluid was calculated using the energy balance on the heat exchanger (Equation 10). For the base case, it was assumed that the stream of brine enters at 95°C and has a fixed temperature drop of 30°C, the temperature drop assumed in a study by Younger et al. [43]. The working fluid was assumed to enter the heat exchanger at approximately 12°C, slightly higher than the cold source temperature of 10°C due to the adiabatic pumping process between points 4 and 1 in Figure 34. It is then successively heated to 95°C until complete evaporation. An evaporating temperature of 95°C and condensing temperature of 12°C gives 35.9 bar to 4.2 bar for the operating pressures of the ORC. The base case mass flow rate for Buzzard produced brine was 352 kg/s, i.e., the most recent mass flow rate shown in Figure 31. The calculated required mass flow rate of the working fluid is 132 kg/s.

The pressure-enthalpy diagram for R134a [142] was used to determine the enthalpies at points 2 and 3 (Appendix D). For saturated vapour at 95°C, the enthalpy is 421 kJ/kg (h_2). It was assumed that there is isentropic expansion in the turbine and therefore, from the pressure-enthalpy diagram, h_3 is 395 kJ/kg. From Equation 15, and assuming no heat loss in the system, the base case work output rate is estimated to be 3384 kJ/s = 3.4 MW. This is 4.7% of the Buzzard Field's 73 MW demand.

The thermal efficiency of the cycle, η, based on the aforementioned parameters is calculated to be 7.8%. This is after Equation 16:

$$\eta = \frac{|W_{out}|}{|Q_{in}|} \tag{16}$$

where W_{out} and Q_{in} are the work output and heat input to the cycle, respectively (Figure 34). The efficiency is low compared to the efficiency that can be achieved in a conventional Rankine cycle, but not unexpected. A state-of-the-art ORC device developed by Climeon [44] is currently the only technology capable of reaching efficiency greater than 10%.

There is uncertainty in some of the adopted parameters including the mass flow rate of brine and the temperature drop of the hot source. Varying the mass flow rate between 299 kg/s and 464 kg/s, taken from recent mass flow rates shown in Figure 31, and varying the temperature drop between 10°C and 50°C, gives a range of work output rate from 1130 kJ/s to 5640 kJ/s (1.13 MW to 5.64 MW). The temperature drop of the hot source has the highest impact on W_t (Figure 36). A hot source temperature of 85°C was also modelled (the lower Buzzard reservoir temperature reported in literature), giving a work output rate of 2.7 kJ/s, and therefore within the aforementioned range.

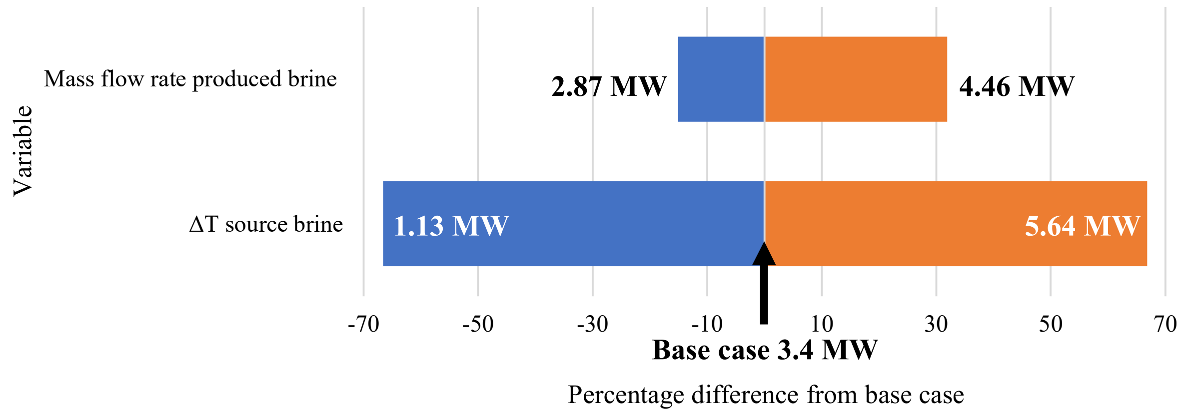


Figure 36: Percentage difference from base case estimate of W_t when varying mass flow rate of produced brine and temperature drop of hot source.

To generate 1 MW, a plant is estimated to have a volume of approximately 35 m^3 with a weight of 150 tonnes [43], and so the space to accommodate a device of up to 3.4 MW capacity offshore would require evaluation.

6.5.4 Comparison with published results

Studies by Auld et al. [9] and Younger et al. [43] quantified the power output from fields in the Brent province of the UK Northern North Sea, obtained by more detailed computational modelling than the present project. Auld et al. [9] estimated maximum power outputs of 0.45 MW to 31.01 MW for brine mass flow rates ranging from 9.29 kg/s to 1231.1 kg/s, respectively. A cross plot showing the maximum power output versus the mass flow rate for the fields considered by the study is shown in Figure 37. There is scatter of the data points around the best fit line on the cross plot, however a direct correlation is not expected because the power output is also dependent on source temperature. The plot gives an indication of the order of magnitude that could be expected from the mass flow rates assumed for Buzzard (black arrow shown in Figure 37). The cross plot shows that a power output between 7 MW and 10 MW could be expected for Buzzard, but there is uncertainty on this range. The reason for the discrepancy between this and the results from the present project is believed to be due to the fixed temperature drop assumed for the brine stream. Auld et al. [9] did not enforce this, and therefore power output was not limited by this assumption of fixed heat input to the ORC.

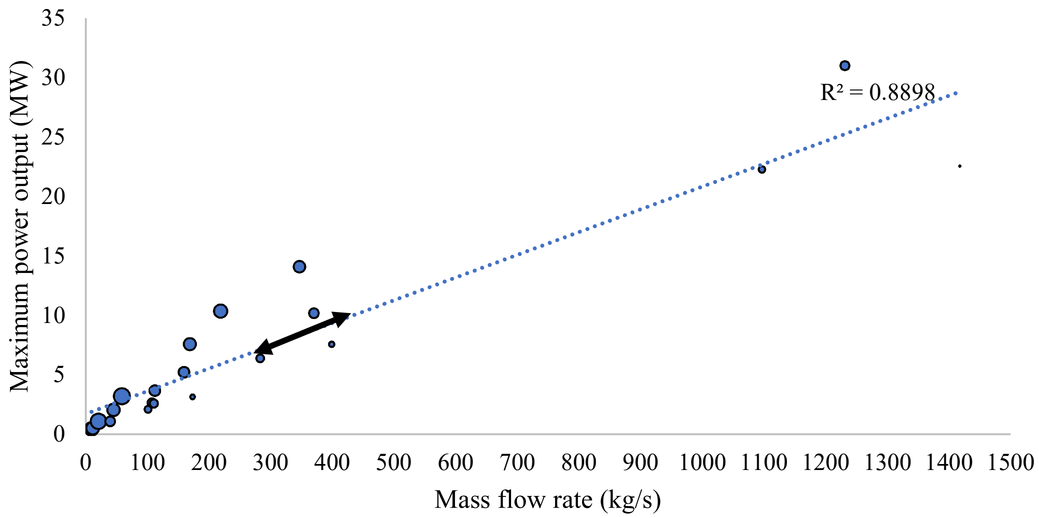


Figure 37: Maximum power output versus mass flow rate for Northern North Sea fields from Auld et al. [9]. Range of mass flow rates assumed for Buzzard indicated by black arrow. Size of circles are proportional to source temperature: largest – 128°C, smallest – 89°C.

A graph of water production rate versus reservoir temperature from Younger et al. [43] shows the predicted power production for sixteen North Sea fields (Figure 38). The range of parameters used to model the power output from an ORC using coproduced brine from Buzzard (described in Section 6.5.3) is included on the graph (box drawn in Figure 38). Based on the data reported by Younger et al. [43], the power production for Buzzard is expected to be in the range between 2.5 MW and 4.5 MW. The calculated base case of 3.4 MW is within this range, and is of the same order of magnitude that would be predicted based on Figure 37 (less than 10 MW), giving confidence in the results obtained.

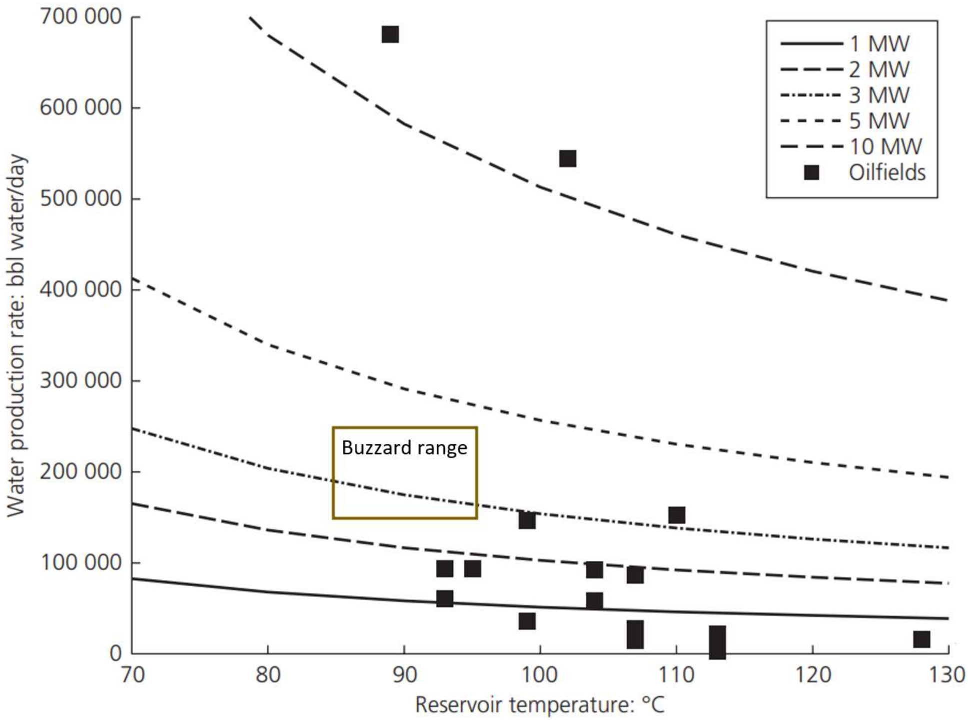


Figure 38: Estimated potential power production for North Sea fields. Temperature and water production rate ranges for Buzzard are indicated. Modified after [43].

6.6 Discussion on geothermal energy

It has been shown that a significant thermal resource exists offshore but there is no nearby market for heat, and transporting it through existing infrastructure would result in substantial heat losses. There is however a demand for low carbon power, and an ORC enables power to be recovered from waste heat and theoretically reduce the demand for fuel gas. The temperature of brine produced from Buzzard has been found to be suitable for electricity production through an ORC. The estimated power output from an ORC for the Buzzard Field is less than 10 MW, and would therefore not meet all of the platform's power needs, but could provide a baseload source of electricity.

This project considers the energy that could be generated through coproduction of geothermal fluid with hydrocarbons. In the future however, offshore geothermal business models could include repurposing, where existing oil and gas infrastructure is converted into a geothermal asset, or standalone, where new sites are developed. The existence of offshore infrastructure in the UK provides excellent access to demonstration sites for geothermal energy, but the potential would need to be considered on a case-by-case basis based on temperature, flow and access to market. Not all existing infrastructure will be suitable for continued use as some wellbores could suffer from degraded mechanical integrity due to their age.

The cost of drilling has historically inhibited investment in geothermal [143]. However, in the coproduction and repurposing models, the capital investment and financial risks are partially mitigated as wells are already drilled. In the wider context, economics should be combined with net zero goals, and carbon taxes should be taken into account. Repurposing suitable offshore oil and gas fields into geothermal assets could delay decommissioning of infrastructure, which across the UKCS is expected to be £39 billion, the majority of which is predicted to be outlaid between 2021 and 2040 [144]. Future oil and gas developments deemed suitable for future geothermal use could consider planning for this at the beginning of project development, such that the facilities can be repurposed at the end of hydrocarbon production.

Although being a relatively immature technology, power production via ORCs from coproduced fluids is likely to see advances in innovation and technology which will drive down cost, analogous to the offshore wind industry.

This concludes the technical assessment of the electrification of offshore power generation. An economic assessment of electrification will now be presented.

7.0 Economic assessment

The economic assessment will estimate the net present value (NPV) of platform electrification and the payback time of installing an ORC system. For the NPV assessment, the electrification of the power generation system of Captain, Buzzard and Golden Eagle is considered as one project.

7.1 Net present value

In Section 3.2.4, it was shown that Moray East wind farm could provide the energy the platforms require over a monthly timeframe, but an assessment of hourly demand and generation (Section 5.2) showed that a backup power solution would be required due to intermittency of the wind resource. It has been recommended by this project that the backup solution be power from shore. The NPV of the preferred power solution has been estimated which, to remind the reader, is:

- Implementing the recommended electricity network described in Section 4.0 (HVAC transmission and a shared distribution hub);
- Using Moray East wind farm to provide the primary source of electricity;
- Utilising power from shore as the backup power solution.

Clearly there will be significant upfront capital expenditure (CAPEX) to electrify the platforms. There will be operating expenditure (OPEX) savings with the move from using gas turbines as the primary energy source to electricity. The main expenditure, savings and benefits are listed in Table 12.

Table 12: Main outgoings, savings and benefits associated with electrification of the power generation systems of the Captain, Buzzard and Golden Eagle platforms.

	Item	Unit cost	Outgoing / saving / benefit
1	Distribution hub	£650m [6]	Outgoing (CAPEX)
2	Platform modifications	£149m/platform [6]	Outgoing (CAPEX)
3	Submarine HVAC cables	£2.5m/km [145]	Outgoing (CAPEX)
4	Cost of wind power	£57.50/MWh[32] [108]	Outgoing (OPEX)
5	Cost of backup power from shore	£129/MWh[33] [107]	Outgoing (OPEX)
6	Saving on fuel gas purchased	£15/MWh[34] [106]	Saving (OPEX)
7	Captain gas revenue	£9.60/MWh[35] [146]	Benefit
8	Carbon tax avoided	£50/tonne CO_2 [110]	Saving (OPEX)
9	Gas turbine OPEX avoided	£6m/year/platform [6]	Saving (OPEX)

Key assumptions made to estimate NPV are:

- Major modifications will be made to one platform per field.
- Length of submarine cables are as shown in Figure 22b. The transmission link from the wind farm to shore is not included because this is already under construction.
- Power from shore accounts for 230 GWh electricity use (Section 5.0).
- Power from wind accounts for 815 GWh electricity use (total demand of 1045 GWh minus backup requirement of 230 GWh).
- Only Buzzard and Golden Eagle will save on fuel gas purchased.
- Captain uses produced gas for fuel so the gas no longer required for fuel could be sold.
- Carbon tax or participation in an ETS could impact the upstream industry in future and so has been included in the calculation.

A cash flow model was built over a 15-year time period (Appendix E). Line items 1 to 3 in Table 12 are assumed to be upfront CAPEX in the first year and so have not been discounted. Line items 4 to 9 are annual OPEX and were discounted using Equation 17 [9]:

$$Discounted\ present\ value = \frac{Future\ value}{(1+D)^n} \quad (17)$$

where D is the discount rate (10%, [147]) and n is the number of years from the present. Inflation was not taken into account. The discounted cash flow each year over the 15-year

[32] Moray East wind farm strike price.
[33] Average unit price of electricity for large business in 2021.
[34] Wholesale gas price.
[35] Natural gas price on 28 July 2021 with 1 USD = 0.72 GBP.

period was summed for line items 4 to 9. The present value of all entries in Table 12 is shown in Figure 39. The NPV is estimated to be -£1340 million, showing that based on this economic assessment, the project would not break even. A government subsidy or some other form of incentive is likely to be required for the project to be implemented.

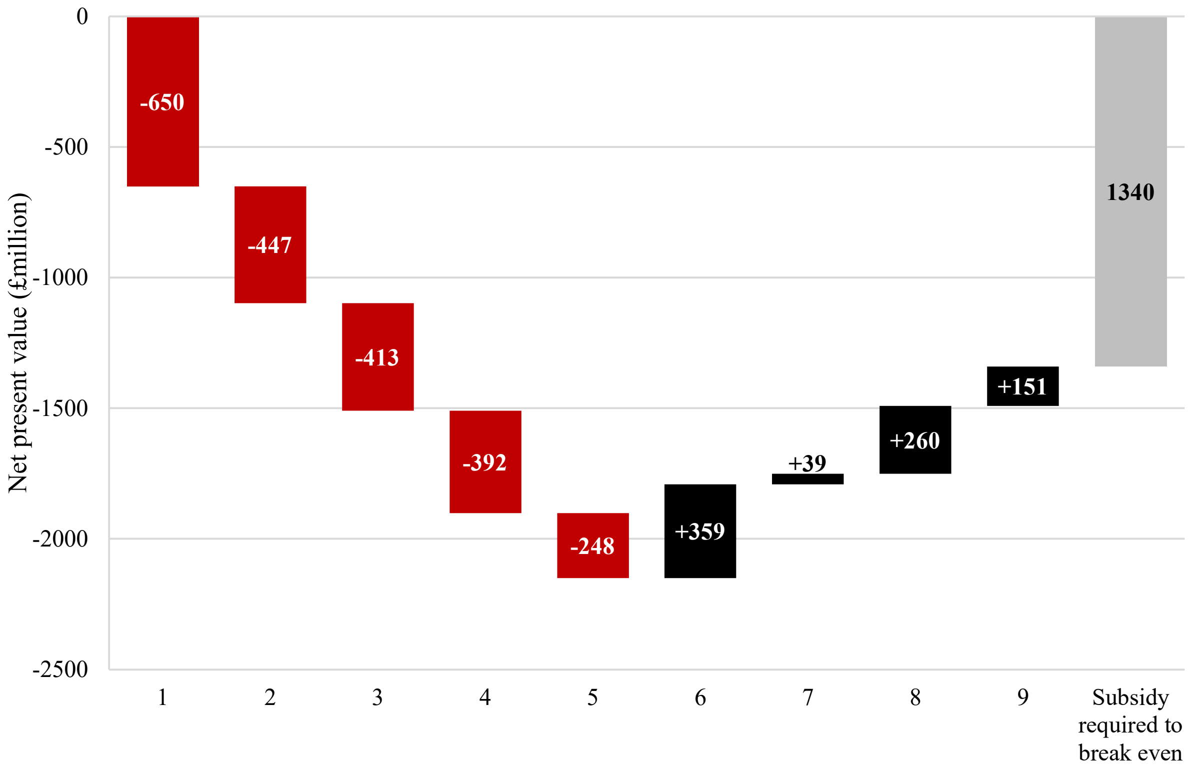


Figure 39: NPV for complete electrification of the platforms using wind as the primary power source and power from shore as backup. Numbers on x-axis correspond to line items in Table 12. NPV is -£1340 million showing that the project would does not break even based on this analysis.

Despite the potential for OPEX savings related to retiring gas turbines as the primary means of power generation, the high upfront costs exceed these benefits over the project lifetime. The CAPEX of the electricity infrastructure accounts for more than 65% of the outgoings (Figure 40).

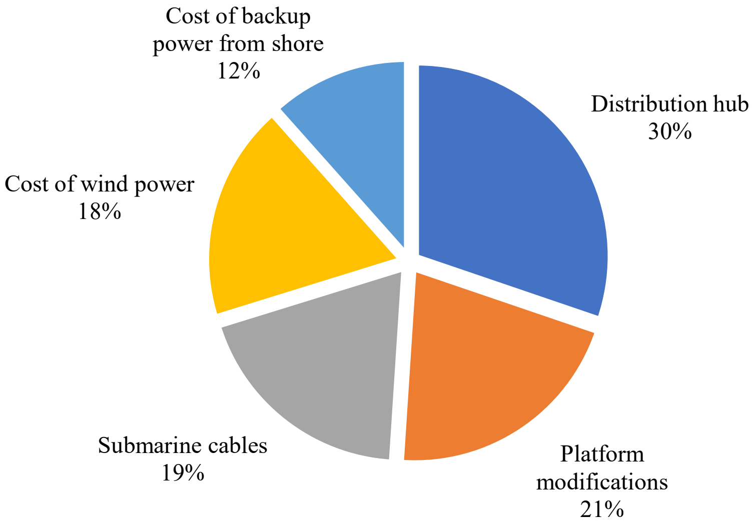


Figure 40: Breakdown of electrification project outgoings listed in Table 12. Assumes a 15-year timeframe. Annual cost of wind power and backup power have been discounted as described in the main text.

7.2 ORC system payback time

Analysis presented in Section 6.5 showed that an ORC system could be capable of providing 3.4 MW of power (base case estimate). The payback time of such a system has been calculated based on the cost of fuel gas required to provide the same amount of power, similar to the methodology presented by Auld et al. [9]. Operating and maintenance costs for the ORC and gas turbines are assumed to be equal. A cash flow model was built using a range of projected wholesale gas prices (Figure 41).

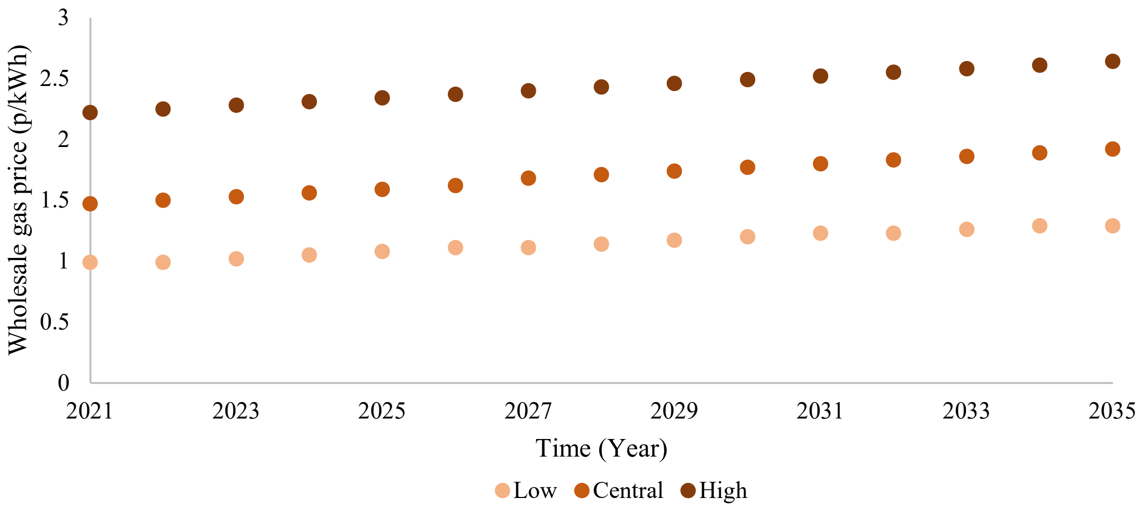


Figure 41: UK Government wholesale gas price assumptions 2021 to 2035 (not discounted). Data sourced from [148].

The cost of the ORC system was assumed to be CAPEX in the first year only and in subsequent years the cost of fuel for the ORC is zero because the geothermal fluid is produced from the field. The cost per kW of installed capacity of ORC is estimated to range from £1200 to £3600 [43] with a central value of £2500/kWh [9]. The cash flow over the 15-year time period was discounted using Equation 17 and a discount rate of 10% (Figure 42). The mid-case payback time of a 3.4 MW capacity ORC system would be 7.03 years. This is greater than reported by Auld et al. [9] who estimated a payback time range of between 3.09 years and 4.53 years for a 10 MW capacity ORC system. However, the study was published in 2013 when natural gas commodity prices were higher than at present.

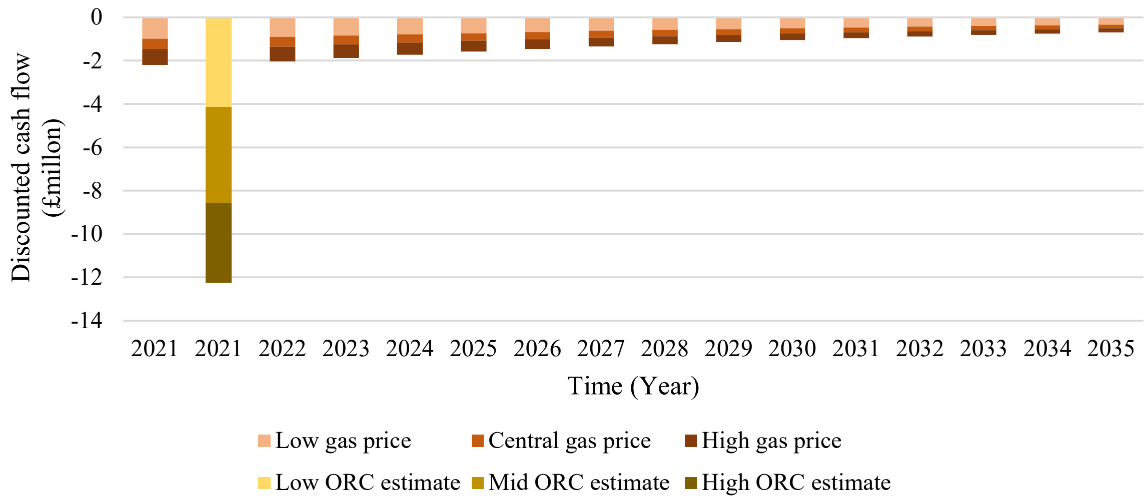


Figure 42: Discounted cash flow based on ranges of wholesale gas price and ORC system installation cost.

7.3 Discussion on economic assessment

The NPV of the project to electrify the power generation system demonstrates the economic challenge of electrification, which has also been recognised by the OGA [6]. There is high upfront CAPEX, partly because of the modifications that would be required for the brownfield developments, which is a key economic driver. The analysis has also demonstrated the electricity price disparity between power from shore and from offshore wind (also shown in Section 5.5). It is estimated that over a 15-year project lifetime, the cost of receiving approximately 20% of the platforms' power needs from the onshore electricity grid would be 40% of the total electricity cost[36] (Figure 39). There will be other outgoings, benefits and savings that could form part of this analysis, but the items included here are deemed to be the most significant.

To break even with the outgoings presented in Table 12 and the estimated NPV of the savings and benefits, a greater than 50% reduction in the cost of the outgoings would need to be

[36] £248million/(£248million + £392million) = 0.39.

realised. Subsidies or tax breaks could make the project more economically competitive. The UK Government has in the past provided financial incentives to the oil and gas industry when it has faced challenging economic conditions. The government has however stated that any future support will be in the context of delivering the UK's net zero target and be dependent on the sector adopting emissions-reducing measures [8].

The economic assessment performed here does not take into account the future CAPEX of decommissioning the installed platforms. The Brent Field alone, which has the same number of platforms as Buzzard (four), is expected to have a total decommissioning cost of several billion pounds [149]. Electrification of the platforms could extend their life beyond use for oil and gas production, and potentially allow the depleted hydrocarbon fields and their infrastructure to be used for carbon capture and storage (CCS) sites. This repurposing could delay or negate the need to decommission the assets and make the economics of electrification more attractive on balance. Developing hydrogen production offshore is another possible way that the infrastructure could be reused, however both this and CCS would depend on the life span of assets being prolonged, which could be achieved through electrification. There is a paradigm shift underway in terms of the UK's energy use and distribution, and the oil and gas sector should see itself as part of an energy industry that can make a positive contribution to the energy transition by considering the use that its assets could have once hydrocarbon production is either uneconomic or not socially acceptable.

The gas price and ORC installation cost influence the payback time of the ORC system, of which the mid-case is 7.03 years. A capacity of 3.4 MW would only be capable of providing 4.7% of the Buzzard Field's power requirements. Therefore, it may not be a worthwhile investment because another power source would still be required to meet the majority of demand.

8.0 Discussion

The present project aimed to investigate the possibility of using renewable energies to provide electricity and thereby meet the platform power demands of three offshore oil and gas fields in the UK North Sea with the following main objectives:

- Calculate energy yields and assess to what extent the platforms' power demands could be met by renewables;
- Propose an electricity network layout to electrify the platforms;
- Critically assess backup power options and recommend a backup power solution;
- Carry out an economic assessment of the electrification of the power generation systems.

To reduce the carbon intensity of offshore power generation, renewable energies that could be readily accessed were considered: wind energy from the under-construction Moray East offshore wind farm, and power production through coproduced geothermal fluid. These were chosen because electrification of the power generation system offshore will face fewer barriers if operators can employ technologies that are relatively straightforward to implement.

It is estimated that Moray East offshore wind farm could provide 78% of the energy demand of the platforms considered. Despite a capacity of 950 MW, there is intermittency in the climate-based wind resource and so the full power demand of the platforms cannot be met at all times. This is in agreement with other studies such as Marvik et al. [24], He et al. [23] and Korpås et al. [19] which have assumed that if wind power were to be used as an energy source, it should be integrated with other technologies. The implication of being able to meet 78% of the demand from wind is that there is scope for a high proportion of the platforms' energy demands to be met from a renewable source which is situated 100 km or less from the location of the platforms. The wind farm also has no build costs from the point of view of the oil and gas operators.

Wind data from 2019 for the nearest onshore weather station to the wind farm site were used as the starting point for the wind energy yield assessment. Wind speeds were scaled up to better match the offshore environment, as described in Section 3.2.1. This has given a deterministic view on power and energy generation from the wind farm. For a more robust conclusion on variability in power output and energy yield, weather station wind speeds for other years could be used in the first instance and a probabilistic analysis conducted. It was not possible to do this because of dataset completeness limitations; 2019 was used because it was the most complete dataset available for the last five years. Recorded offshore wind speeds at the wind farm location would be more preferable still. Despite this limitation, results obtained agree with the wind farm developer's assessment of the number of homes that could be powered by Moray East (Section 3.2.3), giving confidence in the results presented.

A detailed analysis of the requirements for the network required for large scale electrification is beyond the scope of this project and has not been investigated in depth. Electrification of offshore platforms has already been delivered in Norway, and so the technical solutions to achieve it are available. The results of the NPV assessment show that the barrier to electrification could be more economic, rather than technical.

In addition to the previous considerations, the feasibility of using coproduced brine via organic Rankine cycles has been evaluated. The range of electrical output from an ORC using coproduced brine from the Buzzard Field is estimated to be 1.1 MW to 5.6 MW, based on historical water production data. This range, and the base case estimate of 3.4 MW, assume that the mass flow rates required to heat the working fluid to the temperature of the hot source can be supported by an ORC system. If data can be obtained, a study into on the market ORC systems could determine if this power output can be achieved, or if the mass flow rates and ultimately power output would be lower than those estimated here. The order of magnitude of the calculated power output range does however agree with other assessments presented in literature [9], [43] which were obtained by more detailed modelling, validating the results obtained. This project considered the power output from an ORC using R134a as the working fluid. If the thermodynamic data can be obtained, the use of different working fluids could be investigated to determine if power output can be improved.

Clearly, the economics of electrification are challenging. However, it is not a project that an oil and gas operator can carry out in isolation, and will require collaboration and/or government financial support. The economic assessment carried out here could be improved upon by using a range of cost estimates to characterise the range of possible outcomes. These were not available for this project, but it is expected that the NPV would remain negative nonetheless. A multidisciplinary approach is also required, involving expertise from (but not limited to) electrical and mechanical engineers, financial planners, economists, electricity infrastructure owners and renewables developers to build a more detailed picture of the requirements for electrification.

Finding ways to make the oil and gas industry "greener", such as by reducing the carbon footprint of offshore power generation as studied in this project, could be considered by some as "greenwashing[37]". However, given the dependency on fossil fuels for the UK's energy needs and other uses, the tax revenue generated by the oil and gas industry (£350 billion since 1970 [8]), the number of jobs it supports and the energy security that it arguably provides, it would be naïve to expect that it will be imminently phased out in its entirety. The UK Government has made clear that the oil and gas industry, albeit operating within a net zero basin, will continue to contribute to the energy mix in 2050 through its inclusion in the 2020 Energy White Paper [8]. So, if the industry is here to stay for the foreseeable future, then there is a real need to reduce its impact on the environment.

This project has contributed to the growing body of knowledge and understanding regarding the feasibility of low carbon energy projects in the UKCS. In this way, it is hoped that the project will play a part in realising the future net zero energy system of the UKCS.

[37] Greenwashing: "Behaviour or activities that make people believe that a company is doing more to protect the environment than it really is". [152]

9.0 Conclusions

Wind and geothermal have been identified as accessible renewable energy sources that can be used to provide zero carbon electricity to the platforms of the Captain, Buzzard and Golden Eagle UK North Sea fields. Moray East has been identified as the best offshore wind farm candidate and is recommended as the primary electricity source to replace existing gas turbines. Output from the Moray East offshore wind farm could meet 78% of the platforms' energy demands. Intermittency of the wind resource results in the requirement for a backup power source which is recommended to be power from the onshore National Grid. Implementing this combination of power supplies could save over 600,000 tonnes CO_2 annually from the current power generation systems.

Coproduced water from the fields studied is a low enthalpy geothermal heat source with theoretical thermal power output ranging from 36 MW_{th} to 162 MW_{th}. Hot coproduced water transported using existing pipelines would be subject to high conductive heat losses, and as such, a useful purpose for the thermal energy has not been identified at this time. The temperature of coproduced water from the Buzzard Field has been found to be suitable for electricity production through an organic Rankine cycle (ORC), which could generate 3.4 MW (base case) electrical power baseload. This is 4.7% of the power demand of the Buzzard Field platforms. An ORC system with 3.4 MW installed capacity is estimated to have a mid-case payback time of 7.03 years.

HVAC transmission from the wind farm to the platforms via a distribution hub is recommended for the electricity network. The voltage would be transformed at the distribution hub and supplied to the platforms at the required voltage and frequency for use.

Complete electrification of the power generation system of the Captain, Buzzard and Golden Eagle platforms has high CAPEX but benefits and OPEX savings would also be realised. On balance however, due to the magnitude of the expected CAPEX, overall project NPV is negative.

In conclusion, the present analysis has shown the technical feasibility of the proposed project. Nevertheless, complete electrification of the power generation systems faces economic challenges. Government subsidy, or regulation mandating electrification, would be required for the project to be implemented in the UK and the CO_2 reductions realised.

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11.0 Appendices

11.1 Appendix A

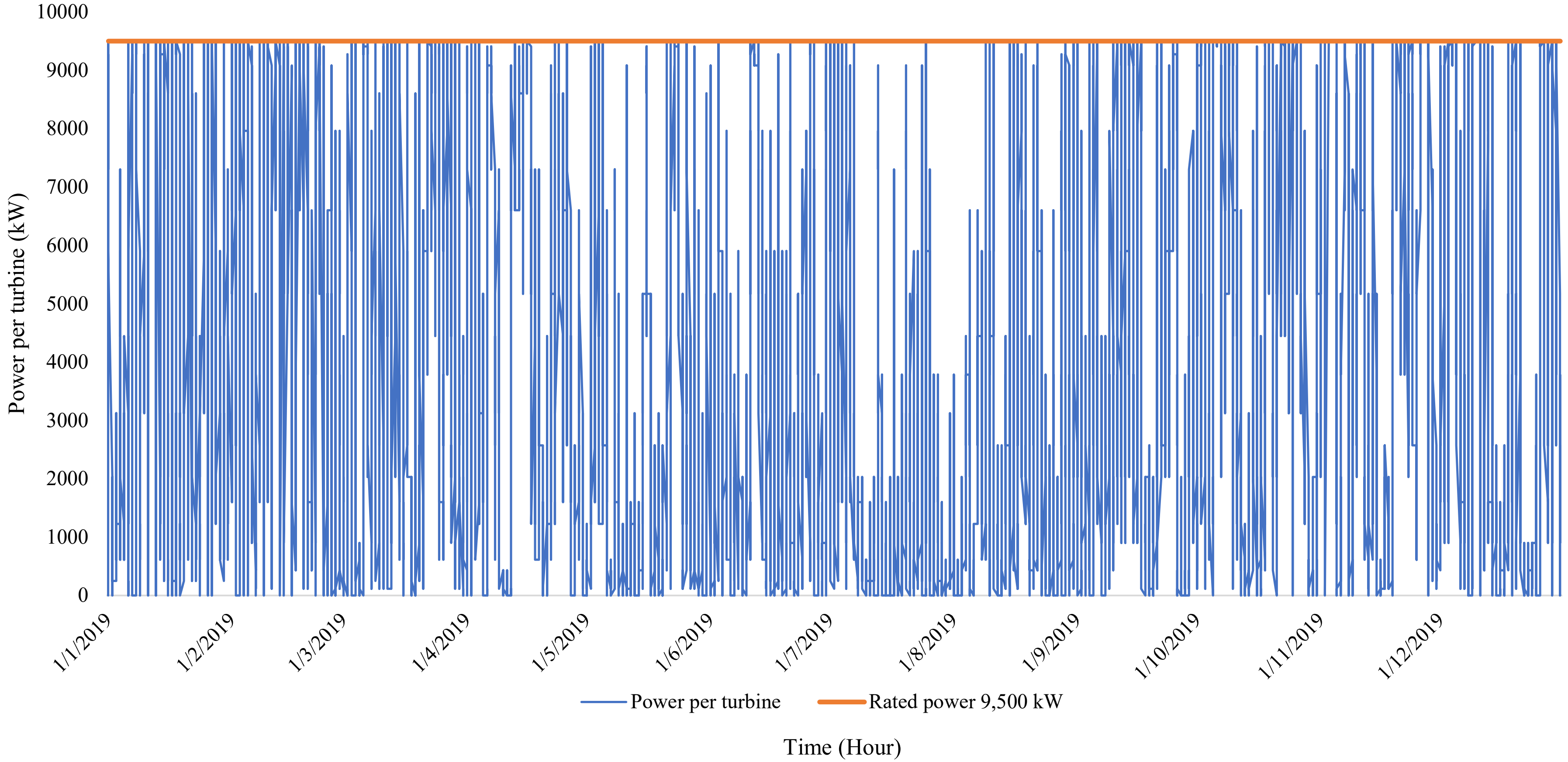

Figure A 1: Power generated by one wind turbine in one year.

11.2 Appendix B

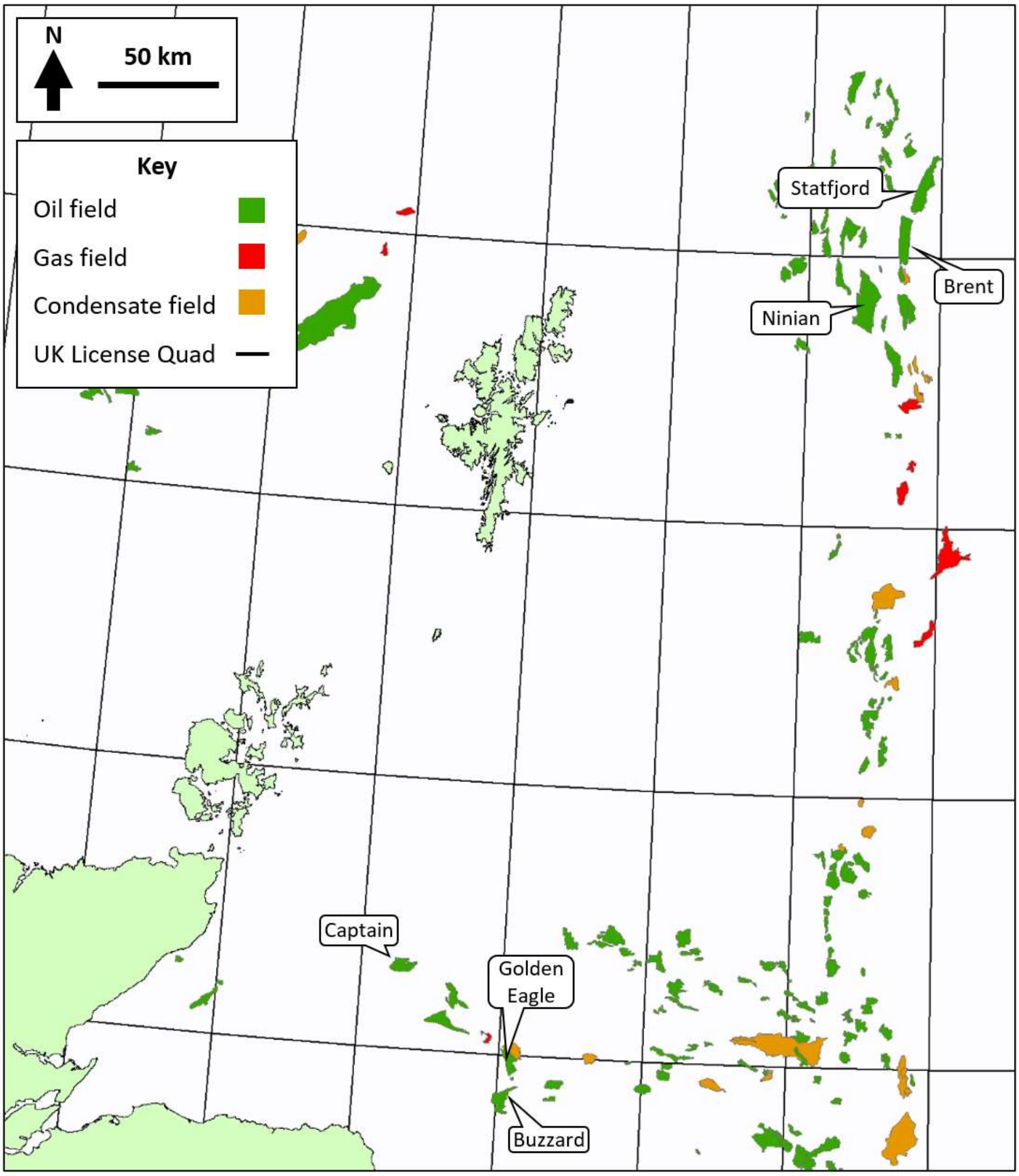

Figure B 1: Location of Ninian, Brent and Statfjord Fields.

11.3 Appendix C

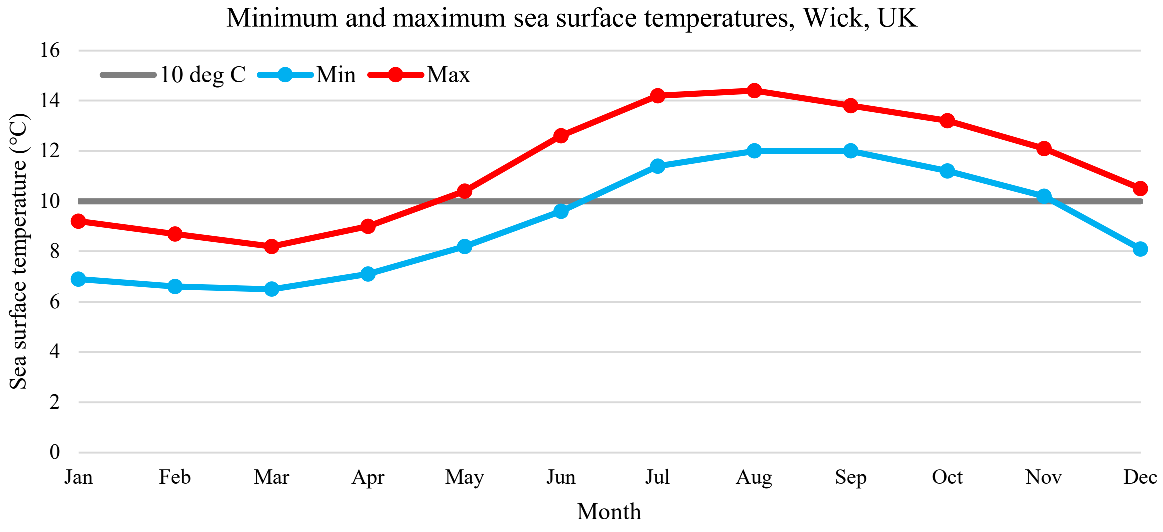

Figure C 1: Sea surface temperatures at Wick, UK [132].

11.4 Appendix D

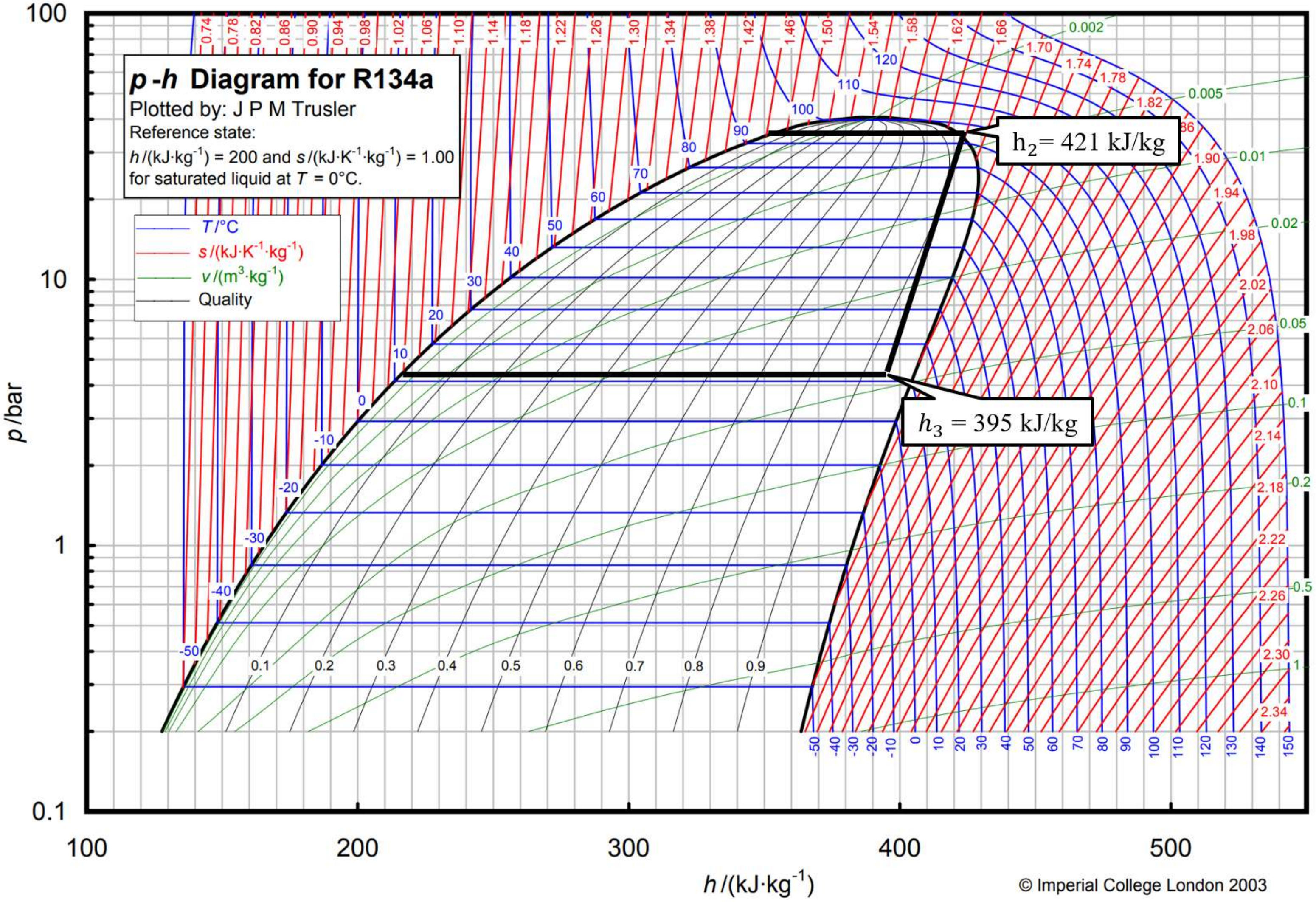

Figure D 1: Pressure-enthalpy diagram for R134a [141].

11.5 Appendix E

Table E 1: Cash flow model for NPV assessment. All monetary values in millions of pounds (£m).

Year	Cost of wind power	Cost of backup power from shore	Saving on fuel gas purchased	Captain gas revenue	Carbon tax avoided	Gas turbine OPEX avoided
0	47	30	43	5	31	18
1	43	27	39	4	28	16
2	39	25	35	4	26	15
3	35	22	32	4	23	14
4	32	20	29	3	21	12
5	29	18	27	3	19	11
6	26	17	24	3	18	10
7	24	15	22	2	16	9
8	22	14	20	2	15	8
9	20	13	18	2	13	8
10	18	11	17	2	12	7
11	16	10	15	2	11	6
12	15	9	14	2	10	6
13	14	9	12	1	9	5
14	12	8	11	1	8	5
NPV (£m)	**392**	**248**	**359**	**39**	**260**	**151**