NORCE Norwegian Research Centre AS
www.norceresearch.no

Project economics of offshore windfarms. A business case[1]

Petter Osmundsen, Magne Emhjellen-Stendal** og Sindre Lorentzen*

*Universitetet i Stavanger (UiS); **Petoro ASA

Rapport nr. 32 2021 NORCE Samfunn

Abstract:

This report examines offshore wind investment by oil companies by means of a transparent and pedagogic project economics analysis. We discuss financing and economic return. Offshore windfarms are organised as special purpose vehicle (SPV) companies. We analyse the economic interactions between the SPVs and the oil companies, and address financing and accounting issues. Finally, we present potential challenges to the petroleum resource authorities from this change in the European majors' investment strategy. Unlike windfarms onshore, offshore windfarms did not see cost reductions for many years. The wind turbine generators moved farther ashore and on deeper water, and the life cycle cost was actually increasing. Apparently, we now see a dramatic change. In aggressive bidding for Contracts for Difference in the UK, we have seen the strike price fall from around GBP 150/MWh in 2015 to around GBP 40/MWh in the auction rounds in 2019 (in 2012 terms). A question is how this will impact profitability of new development projects. Does the reduction in the strike price reflect a reduction in project cost or a reduction in project profitability, or maybe both? We examine this with a transparent project economics analysis of the bottom-fixed Dogger Bank project, owned by Equinor, SSE Renewables and ENI. It is the largest offshore windfarm project in the world and is set out to generate 5% of UK electricity production.

[1] Lorentzen and Osmundsen are thankful to the Ministry of Petroleum and Energy for research funding. We very much appreciate useful comments and suggestions from Trond Bjørnenak, Atle Blomgren, Peter Enevoldsen, Harald Espedal, Stein-Erik Fleten, Frøystein Gjesdal, Odd Rune Heggheim, Kristian Holm, Asbjørn Høivik, Thore Johnsen, Jon Lerche, Li Lu, Morten Pedersen, Anders Myhr, Kjell Over Røsok, Teodor Sveen-Nilsen and Hans Wilhelm Vedøy. All analysis and conclusions are solely the responsibility of the authors.

Rapporttittel/ Report title	Project economics of offshore windfarms. A business case
Prosjektnummer/ Project No	103152 Læringsprosesser fra norskbasert petroleumsvirksomhet
Institusjon/ Institution	NORCE Samfunn
Oppdragsgiver(e)/ Client(s)	Olje- og energidepartementet (OED)
Gradering/ Classification:	Åpen
Rapportnr/ Report No.	NORCE rapport nr. 32 2021
ISBN	978-82-8408-187-8
Antall sider/ No. of pages	46
Publiseringsdato/ Date of publ.:	November 2021
Stikkord/ Keywords	Offshore wind, petroleum, business case, investments

Project economics of offshore windfarms. A business case[2]

Petter Osmundsen*, Magne Emhjellen-Stendal** and Sindre Lorentzen*

University of Stavanger

***Petoro ASA*

Abstract

European petroleum majors have moved into offshore windfarm projects, with large investments and ambitious capacity and production targets. The projects have many opportunities for the supplier industry, e.g., construction industry and maritime industry. Oil companies make use of some of the same suppliers they have in oil extraction projects, and there is potential for knowledge transfer from petroleum to the windfarm industry. We examine offshore wind investment by oil companies by means of a transparent and pedagogic project economics analysis. We discuss financing and economic return. Offshore windfarms are organised as special purpose vehicle (SPV) companies. We analyse the economic interactions between the SPVs and the oil companies, and address financing and accounting issues. Finally, we present potential challenges to the petroleum resource authorities from this change in the European majors' investment strategy.

Unlike windfarms onshore, offshore windfarms did not see cost reductions for many years. The wind turbine generators moved farther ashore and on deeper water, and the life cycle cost was actually increasing. Apparently, we now see a dramatic change. In aggressive bidding for Contracts for Difference in the UK, we have seen the strike price fall from around GBP 150/MWh in 2015 to around GBP 40/MWh in the auction rounds in 2019 (in 2012 terms). A question is how this will impact profitability of new development projects. Does the reduction in the strike price reflect a reduction in project cost or a reduction in project profitability, or maybe both? We examine this with a transparent project economics analysis of the bottom-fixed Dogger Bank project, owned by Equinor, SSE Renewables and ENI. It is the largest offshore windfarm project in the world and is set out to generate 5% of UK electricity production.

[2] Lorentzen and Osmundsen are thankful to the Ministry of Petroleum and Energy for research funding. We very much appreciate useful comments and suggestions from Trond Bjørnenak, Atle Blomgren, Peter Enevoldsen, Harald Espedal, Stein-Erik Fleten, Frøystein Gjesdal, Odd Rune Heggheim, Kristian Holm, Asbjørn Høivik, Thore Johnsen, Jon Lerche, Li Lu, Morten Pedersen, Anders Myhr, Kjell Over Røsok, Teodor Sveen-Nilsen and Hans Wilhelm Vedøy. All analysis and conclusions are solely the responsibility of the authors.

1. Introduction

Oil companies have moved into offshore windfarm projects, with large investments. They have a good starting position, with experience in managing large capital-intensive offshore projects and evaluating developments in energy markets. The projects have many opportunities for the supplier industry, e.g., the construction and the maritime industry. Oil companies make use of some of the same suppliers they have in oil extraction projects, and there is potential for knowledge transfer from petroleum to the windfarm industry. One example is the experience with HVDC-transmission used in the electrification of offshore petroleum installations on the Norwegian continental shelf. This is relevant now as windfarms move farther ashore. New technology is also developed when wind turbine generators are to partially supply the electricity at the Tampen petroleum extraction area, in the Hywind project applying floating wind turbine generators.

A vital question to petroleum extraction countries is whether the offshore wind industry can serve some of the same functions for the economy as the petroleum industry. Blomgren (2021) identifies six characteristics of the petroleum industry that makes it a particular important driver for the Norwegian economy:

1) High profitability. High margins mean high tax payments and also make the industry willing to buy the best and most sophisticated solutions and services from the supply industry.
2) Exports. Petroleum is the main Norwegian export industry.
3) Procurement. The share of procurement going to Norwegian suppliers is very high.
4) Level of R&D. High technological complexity implies a high level of R&D, much of which is sourced out to Norwegian suppliers.
5) Co-operation over innovation activity. The petroleum industry actively involves Norwegian suppliers in product and service development, securing high learning effects.
6) Import shares in procurement. The low import share indicates a local supplier industry that is capable of delivering the products and services demanded.

In this paper we will address the first and most important point of spillover effects to the supply industry; profitability. Evaluation of company profitability of offshore wind is of course also crucial to determine for other parties and purposes, e.g., for investors and for governments that design framework conditions.

To assess the effect on overall economic activity from an expansion in windfarm projects by oil companies, one has to ascertain the future profitability and public and private funding of windfarm development projects and thereby the size of this activity. In addition, one has to ascertain the effect it has on petroleum investment. For both effects, the profitability of windfarm projects seen from the perspective of an oil company is crucial. To evaluate the developers' profitability, we will consider a specific windfarm project as a business case, the Dogger Bank windfarm. Since many of the major oil companies is now entering offshore windfarm developments with very ambitious growth targets, and since oil companies are the owners of 60% of Dogger bank, we choose to evaluate the project seen from the perspective of an oil company.

To ascertain the effect on overall investment, and the distribution of the activity over the business cycle, we must also examine whether there are any financial connections within an oil company by which windfarm investment affect investment in oil and gas projects. This is essential to petroleum extraction countries since oil and gas projects in these countries generate large tax revenues and often have a large percentage of the investment supplied by local industry. For Norway, more than 80% of the resource rent is captured by the government and local industry supply up to 70% of the development cost. If the dominant company on the Norwegian shelf, Equinor, instead would invest more of its funds in windfarms abroad, there will not be any tax revenue and the fraction of development investment provided by Norwegian supply industry is much lower. Thus, it is essential to determine if the windfarm investment comes instead of investment in oil and natural gas projects or if it comes as a supplement. So far, it has mainly been a supplement. With much more ambitious targets for windfarm investment, this may change. Statements by Shell of gradual managed decline of 1% to 2% per annum of its oil production in the coming years is an indication of the change that is taking place in the major European oil companies.[3] However, Shell is to increase its production of natural gas, so overall petroleum production is to be stable. Nevertheless, annual spending on petroleum exploration has been cut by more than 30%. Petroleum projects are to be profitable on a breakeven oil price of USD 30 per barrel. Shell states that projects are to deliver an IRR of 20 to 25% in a high-grade portfolio with fewer core geographical areas.[4] This means that the extreme capital rationing of 2020, related to COVID-19 and oil price war, is to continue to fund expansion in renewable energy. It remains to be seen whether this strategy will uphold. The rise in prices of oil

[3] https://www.upstreamonline.com/energy-transition/shell-to-oversee-gradual-managed-decline-of-oil-output-van-beurden/2-1-961576

[4] Setting a breakeven price lower than the expected price is tantamount to rationing capital, i.e., to raise the effective rate of return requirement. See Osmundsen et al. (2022).

and natural gas after the relaxation of COVID-19 restrictions have reduced the need for capital rationing.

For petroleum extraction countries this change of strategy by major players raises many challenging questions. One is whether these companies will sell assets to other oil companies that have other strategies and lower rates of return requirements, or whether they will keep the assets and potentially underinvest. The issue of underinvestment is particularly relevant to resource extraction counties, since they have rates of return requirements much lower than 20 to 25%. Another question is whether this high rate of return requirement is only to be used for selecting projects or whether it also will be used when dimensioning the projects actually selected. If the latter is the case, we will see suboptimal development concepts and too few infill wells, causing suboptimal recovery rates (cream skimming, see Hiorth and Osmundsen, 2020). The extent of capital rationing in petroleum investment over time by the European major oil companies will depend on the equity requirement needed to support the offensive targets for offshore windfarm development. High equity requirement curtails the funds available for petroleum projects. The equity needed will depend on the cash flow generated from the windfarm investments. Our estimation, based on the project economics of the Dogger Bank project, is that this activity will be cash negative for a very long time.

Oil companies are particularly active in offshore windfarm development. Morthorst and Kitzing (2016) observe that there is significantly higher energy production from offshore compared to onshore turbines. This is due to more stable wind and higher average wind speed, which means higher utilisation time (capacity factor). On the other hand, they find that offshore wind is still 50% more expensive due to larger structures and more complex installation logistics as well as more costly grid connections. Despite significant larger windparks and expected economies of scale, investment per MW in offshore windparks have according to Morthorst and Kitzing generally been increasing globally, due to increased water depth, longer distance to shore and supply bottlenecks. The development is contrary to onshore windparks, which have seen substantial cost reductions. This is supported by analysis of accounting data in UK windfarms by Aldersey-Williams et al. (2019), but they find a gradual decrease in cost since 2010, measured by Levelised Cost of Energy (LCOE). They observe the dramatic reduction in the strike price in the UK Contract for difference (CfD) awarded (after aggressive bidding), and conclude that very significant cost reductions are needed to safeguard project economics.[5] Their point is that the implied dramatic cost reduction is not supported by the cost of windfarms already in operation. At that time, CfDs were awarded at GBP

[5] CfD is explained here: https://www.emrsettlement.co.uk/about-emr/contracts-for-difference/

57.5/MWh, and current modern wind farms had according to the analysis an LCOE of GBP 100/MWh. One way of achieving this, the authors argue, is for investors to reduce the discount rate, referring to risk reduction to investors by the introduction of CfDs. We would add that the new CfD price format that was introduced in 2013, reduced the risk for developers, and that we have seen reductions in the rate of return requirement also in the following years. This reduced return requirements indicate either a fundamental reduction in perceived risk or simply an acceptance of a reduction in return in response to more fierce bidding; or both.

According to Morthorst and Kitzing (2016), more than 90% of all offshore wind installations are in Europe, and half of these in the UK. The strike price has fallen drastically, from £114.39/MWh in the 2015 CfD auction[6] to just £39.65/MWh in the 2019 auction (in 2012 prices)[7]. The 2019 Dogger Bank award has strike prices of GBP 39.650/MWh for phase A and GBP 41.611/MWh for B and C.[8] IEA (2018) comments that projects with a final investment decision (FID) in 2017 vary drastically from sites commissioned in 2017. They refer to progress in terms of innovation and market maturity, e.g., larger turbines, higher capacity factors, and autonomous inspection and predictive maintenance.

In an article on marginal abatement cost, Kesicki and Strachan (2011) argue that to understand what is likely to happen in renewables markets, one needs to apply a commercial cost-benefit analysis. They state that the private sector will make decisions based on their own cost calculations and higher discount rates than governments. Investment in renewables is to a large extent undertaken by private companies. Thus, risk and return on investment is essential for project sanctioning. Jaraite and Kazukauskas (2013) find that this fact often is ignored in the literature on renewables. They refer to the discussion on the investment effect of feed-in tariffs versus tradeable green certificates and find that existing studies mainly are analytical with theoretical modelling studies that do not discuss the effect on company profitability. They argue for more empirical research that addresses company risk. Scarcity of empirical research relating to renewable investments and policy variables is also highlighted by Aguirre and Ibikunle (2014). Our analysis on the profitability of the Dogger Bank offshore windfarm project is a contribution to fill some of these gaps.

A major challenge in valuation of offshore wind investments is the lack of access to first-hand sources of transparent data of good quality. A cornerstone of governments' policies for energy transition is calculations of LCOE for new energy. Elderer (2015) is critical to the data quality that

---

[6] «Breakdown Information on CfD Auctions», Department of Energy and Climate Change (DECC), 2015.
[7] «Contracts for Difference Allocation Round 3 results», BEIS, 2019.
[8] https://www.gov.uk/government/publications/contracts-for-difference/contract-for-difference

typically is used in these calculations. The data does often not meet scientific requirements of transparency. Elderer points out that the data often is from databases, we note that press reports and reports from consulting companies, without disclosure of the original source and without explanation of how the data was processed. Elderer raises the question that the data can be massaged and unreliable. Aldersey-Williams et al. (2019) concur, “[…] it is clear that such data can be susceptible to manipulation by participants, who might be expected to be concerned to shape policymakers’ opinions in favour of future projects.” They observe that commercial consultants are not open about their data gathering approaches, quoting Ernst & Young (2012) that states that their study is “based on publicly available information sources and average input data”. Aldersey-Williams et al. point out that given the limited opportunity to confirm the validity of the data, they may be vulnerable to selective presentation by developers. According to Partrigde (2018), even for official data validity should be questioned, as these rely on public domain information.

Aldersay-Williams et al. (2019) confirm from reviewing the literature that those data sources that is questioned by Elderer (2015) is precisely those that are used in the literature. They propose and execute an alternative approach that they believe would generate LCOE cost data that are more reliable and relevant. The alternative is to use audited accounting data. Most offshore windfarms are according to Elderer (2015) organised as Special Purpose Vehicle (SPV) companies.[9] Aldersay-Williams et al. (2019) point out that, as a perhaps unintended consequence, detailed cost information is now available by audited accounts submitted to the UK Companies House. These data are according to the authors more reliable for a number of reasons, e.g., auditing standards, the potential for tax investigation, and the requirement for audit. Comparing accounting data with public data from Hughes et al. (2017) and the commercial database 4C Offshore, Aldersay-Williams et al. (2019) find considerable deviation. Although most windfarms have higher accounting cost than in the databases, some windfarms also have substantially lower cost. The latter also applies to some of the recent UK windfarms; West of Duddon, Westermore Rough, and Dudgeon.

LCOE-numbers, as calculated by Aldersey-Williams et al. (2019), are often used by governments, social planners and researchers. We augment this approach, by analysing project economics as seen from the perspective of investors. Relevant metrics are net present value (NPV), internal rate of return (IRR) and payback time. We fully support the approach of Aldersey-Williams et al. (2019) of using accounting numbers, but it has limitations when analysing future projects (Aldersey-Williams et al., 2021). We undertake a case analysis of Dogger Bank, the world’s largest offshore wind fam,

[9] With this organisation, the risk of the windfarm is insulated from the parent company, and sales of assets are easier.

seen from the perspective of the investors. We use data communicated directly by the companies behind the project and supplement the analysis with data from other sources, including research articles and accounting data from other windfarms. Due to uncertainty of input data, we perform sensitivity tests.

Dogger Bank is set to start investment in 2020 and have first production in 2023. Thus, we need to rely on available cost estimates. However, we use historic UK offshore windfarm data to evaluate the input data. We also use more recent accounting data than analysed by Aldersey-Williams et al. (2019). Unlike investment bank reports, our project analysis is transparent. We explain pedagogically how an investment analysis is set up, the data sources we use, and we perform sensitivity analysis. To our knowledge, this has not been done previously in the literature. We evaluate the consequences of simplifying assumptions that are often are made in evaluating windfarm investments. Examples of simplifications are using a fixed operation cost even if it is increasing over time and using a fixed rate of return requirement over the entire project period, even if the risk is considerably higher once the fixed price period is over. We also see examples of analyses where decommissioning cost and transmission loss are unaccounted for. Overall, the simplifications we observe have the effect of overstating expected profitability.

2. Cost

For windfarm projects, some inputs to NPV analysis are available. For the remaining inputs of the analysis, we need to make assumptions. One important parameter that usually is available is an estimate of overall investment, typically referred to as capital expenditure (Capex). Data on the timing of the investment, however, is not always available. Time of production start is often available, so there is information on the duration of the investment period, but not how investment evolves over time. Assumptions need to be made. Operation expenditure (Opex) is typically not available. Assumptions can be made based on accounting data for other windfarms and available research. For projects with CfDs, the fixed electricity price for the duration of the contract is known. Assumptions will have to be made for the electricity price applying for the remainder of the production period.

Opex is in research articles estimated to 25% of overall cost, in net present value terms. Whereas Capex accrues in the first years of a project, Opex accrues over the entire production period. Thus, Opex has a much higher proportion of cost in nominal terms. Financial analyses often make the simplifying assumption that Opex is fixed over time. In reality, Opex increases over time, e.g., due to more need for maintenance, and assumptions need to be made about Opex development.

Production can be estimated by using an estimated Power Capacity Factor (PCF). According to Morthorst and Kitzing (2016), offshore wind farms have considerably higher cost than onshore turbines. However, this is to some extent moderated by a higher capacity factor, i.e., higher total electricity production from the turbines due to higher wind speeds and more consistent wind offshore. For an onshore installation, utilisation time is normally around 2000-2300 h per year, while a typical offshore installation has a utilisation time of 3000 h per year or above.

Dogger Bank Wind Farm consists of three projects: Dogger Bank A (DBA), Dogger Bank B (DBB) and Dogger Bank C (DBC). The aggregate project investment cost is GBP 9 billion. The planned capacity for each project is 1.2 GW. Based on analogous cost estimation, we assume that each project will have an investment cost of GBP 3 billion.

There are two assumptions to be made: the duration of the execution phase and the shape of the cumulative consumption of resources throughout the execution phase. Increasing the duration will decrease the present value of the investment cost but it will also delay the income generated by the wind farm. Hence, whether an increase in the duration increases or decreases the present value of the project becomes an empirical question.

The exact timing of the execution phases of the projects are unknown. We will assume that DBA has its execution phase from 2020 to 2022, DBB from 2021 to 2023 and DBC from 2022 to 2024. Regarding the shape of the cumulative investment we will assume linearity, i.e., that the investment cost is split equally across the years of execution. While it is a stylized fact that the distribution tends to be s-shaped, it has minimal impact on the present value of the investment cost. By assuming linearity rather than a s-shaped curve, parts of the investment cost will come too early and other parts too late. For short durations, we find that this will mostly cancel each other out. Table 1 summarizes our assumptions.

Table 1: Investment cost (real 2020 GBP)

	DBA	DBB	DBC
2020	1 000 000	0	0
2021	1 000 000	1 000 000	0
2022	1 000 000	1 000 000	1 000 000
2023	0	1 000 000	1 000 000
2024	0	0	1 000 000

Assumed annual investment cost for each of the Dogger Bank Wind Farm projects. Project cost estimates are reported in, for instance, Equinor's press release regarding Dogger Bank. Project durations can reasonably be inferred from information provided in the CfDs. The timing of the investment costs is unknown.

3. Revenue

The official website for Dogger Bank wind farm, reports an expected lifespan of 25 years. This operation period is divided into two segments: the first 15 years when the wind farm operates with a fixed electricity price and the last 10 years where it is subjected to market prices. Income is the product of quantity and price. The fixed price is GBP 45.83 for DBA and GBP 48.09 (both numbers are in 2020-terms) for DBB and DBC. The market price is estimated in the following manner. We calculate the average electricity price during the last three years for Denmark and the UK. Being a pioneer in wind power, Denmark has a higher share of wind power in the energy mix, and current Danish prices may thus be indicative of future UK prices. In the case of Denmark, we take the equal average of spot DK1 and spot DK2 from Nord Pool. The currency is converted from DKK to GBP. For the UK we use the wholesale price. The electricity price is in both cases adjusted for inflation. The estimated market price is found by taking an average between these two three-year averages. The annual expected quantity of electricity produced is a simple calculation. The capacity for each of the projects are known: 1.2GW. We multiply 1.2GW with a thousand to change it to MW and then we multiply with 8760 ($= 24\ hours \cdot 365\ days$), i.e., the number of hours in a year. This gives us the max capacity of MWh per year. To find the expected annual production we multiply with the capacity factor, which we assume to be 55%. Equation (1) provides a summary of the income calculation.

$$Income_t = Capacity \cdot 1000 \cdot (24\ hours \cdot 365\ days) \cdot \frac{Capacity}{factor} \cdot price_t \tag{1}$$

We assume that the windfarm will be able to keep a stable production when the turbines get older. There is disagreement in the industry whether this is a realistic assumption. According to industry experts there is reason to be concerned of falling production over time.

4. Rate of return requirement

The majority of the investors in Dogger Bank are oil companies, and with the major oil companies setting ambitious targets for offshore wind production, it is relevant to examine oil company rate of return requirements for an investment in offshore wind with two distinct periods as to the electricity price risk: the first 15 years where the price is fixed by contract, and the second period where the price of electricity will follow market prices. Obviously, the return requirement will be different for the two periods.

We evaluate the project according to standard profitability criteria, e.g., as stated in the 2019 BP 20F report:

> "Investment economics: We consider investment economics against a range of measures including profitability index, internal rate of return, net present value, discounted payback, investment efficiency, using a set of scenarios for commodity prices, margins and carbon prices. Investments are generally considered against internal rate of return hurdles typically set in the mid to high teens. Close attention is paid to discounted payback as a measure of commercial risk…"

When evaluating the required return on the project we apply a normal capital asset pricing model approach. We assume the energy company is using its normalised market value debt/equity structure of 30%. The risk-free rate is normalised as well by assuming a nominal 3% with inflation assumption at 2% (1% real rate).[10] Using a market risk premium of 6.0% (data from Damodaran's web site, January 5th, 2021), assuming a bond beta of about 0.3, resulting in an expected return

[10] The historic spread in return between short term T-bills and long-term government bonds is in the range of 1.5-3% in the US depending on periods chosen.

difference above the risk free rate of 1.8%. We use this normalized return requirement of 4.8% for long term debt.

As an estimate of the beta risk of the project in the period with market exposed prices, we observe an unlevered beta estimate of 0.67 for new energy (using data from Damodaran's web site, January 5th, 2021). This New energy group, however, includes many companies with fixed price contracts, thus lowering the beta estimate. We choose to use an unleveraged beta of 1 which is in the normal range for energy companies exposed to market price risk. Given the implied debt percentage financing of 30%, this gives a nominal required return on equity of 10.49% (levered beta equal to 1.25). The weighted average after-tax cost of total capital (WACC) is then estimated to a nominal rate of 8.54% (with a tax rate of 17%).

In the period with fixed contract prices, the beta estimate must be much lower. However, there is still systematic risk and other factors that normally would require additional return to an investor. Exactly how large this additional return requirement should be, is difficult to assess from market data. We assume that this demands a beta of 0.2 above the default spread beta of 0.3 (total unlevered beta of 0.5). This seems reasonable based on beta of new energy companies with mostly fixed price contracts (Osmundsen and Emhjellen-Stendal, 2022). With the above assumption the weighted average cost of capital requirement for total capital in the fixed price contract period is therefore assessed at a nominal 5.92% (6.75% required return on equity).[11]

When determining discount rates for petroleum investments, petroleum companies add around 2% to the calculated WACC to account for development cost for projects that are not sanctioned, overhead cost that are not allocated to projects, and for capital rationing. We have not made such an addition in our valuation case.

The project has high gearing. Dogger Bank A and B are being project financed with gearing of 65% to 70% for the generation assets. Gearing on the transmission facilities is set to 90% of the forecasted OFTO sale proceeds.[12] The owners of the Dudgeon wind farm, Equinor, Masdar and China Resources Group, have signed a hybrid refinancing of GBP 1.4 billion, with A- (EXP) rating.[13] The loan rate is not disclosed. According to WindEurope (2019), interest rates for loans to offshore wind projects in the UK have fallen dramatically the last ten years, and for 2019 they indicate a loan rate

11 The detail in return requirements is only to show equal NPV of project using the respective return requirements for each cashflow.

[12] https://www.equinor.com/en/news/20201126-doggerbank-financial.html

[13] https://www.equinor.com/en/news/2018-12-12-dudgeon.html

in the range 1 to 1.5 percentage points above Libor.[14] From the Dudgeon windfarm accounts, an interest rate of 2.74% is disclosed for the facility, starting in December 2018. With high gearing there is risk exposure related to an increase in interest rates. Dogger Bank windfarm has low margins, a locked-in power price for the first 15 years, and long duration. Thus, it is very exposed to an increase in interest rates. Accordingly, banks normally require part of this this exposure to be secured.

We apply the standard oil company practise of using its normalised market value debt/equity structure for the oil company in setting the WACC, and not the debt ratio and interest rate on project finance. Project finance is not ascribed to projects in oil companies' valuation and ranking projects. If this were to be the case, oil projects could increase the debt ratio and show much higher profitability.

When reporting profitability in windfarm investment, investors and financial analysts often report return on equity. This could be strategic, with the return on overall capital being low. However, increasing debt does according to finance research not cause an increase in market value; the irrelevance theorem by Modigliani and Miller (1958). Market value is determined by net present value of the project cash flow, not its funding. The argument is that increased debt increases risk, and with corresponding increased rate of return requirement, increased debt rate will entail no change in market value. In the wind farm industry, at least for the time being, this basic finance result does not seem to apply in project presentations, and perhaps not in market values. Possible reasons are that investors are not fully aware of the off-balance debt, or that they perceive the activity as low risk irrespective of the size of the debt rate. Our sensitivity results on return on equity on the Dogger Bank project are in accordance with the Miller-Modigliani theorem. A debt rate of roughly 70% generates large variance in equity return. The cost of equity would rise with leverage, because the risk of equity rises. We demonstrate that NPV of the project is equal whether using the equity cashflow or the total capital cashflow when using the respective correct required rates of return in discounting. We calculate several sensitivities to the economics of the project, and with respect to debt we include one with the effect of lower corporate debt financing in the WACC and in addition a sensitivity with both low interest rate and a higher project debt ratio that we see in presentations of windfarm projects by oil companies and investments banks. These are included for illustration purposes, we do not consider them to be consistent valuations of the project.

One obvious problem for an oil company investing in windfarms, would be that the debt ratio increased and the return on average capital employed went down, thus losing out on two key metrics in financial benchmarking towards oil companies with less new energy investment

[14] https://www.global-rates.com/en/interest-rates/libor/british-pound-sterling/2019.aspx

(Osmundsen et al., 2006, 2007).[15] However, with the windfarms organised as SPVs without parental loan guarantees, accounting is done by the equity method. This means that the debt of the windfarms will be off balance for the oil companies, and thus not included in the RoACE calculation.[16] It is only equity and return on equity that affects the balance sheet and the profit and loss account, respectively (the equity method in accounting), and the equity return is fairly high as it accounts for high project gearing and current low interest rates. Accordingly, overall RoACE-calculations for an oil company will not be so strongly affected by entering into low-return windfarm projects, due to accounting arrangements that are standard for investment in the windfarm business. Since the equity method implies that the share of the windfarm profits is shown as a single number in the financial statement, there are many financial metrics that can be distorted and less informative if the project or the investment segment represent a substantial part of the overall business. There is no established practise for where in the financial statement the share of the profits is to be posted, e.g., if it is posted as revenue it will show a very high profitability as there is no accompanying cost posting.

When windfarm investment goes from being a minor activity to being one of the two main activities, however, investors need more information. Equinor decided that the windfarm activity is to be reported as a separate business segment. IASB works on a new accounting standard where more precise reporting is proposed when using the equity method.[17] Suggested changes, if approved, will make it easier to calculate a separate rentability for oil companies' windfarm investment, by comparing the result with capital invested. A reason to analyse this investment separately is that the rate of return requirement deviates from the core activity. On the one hand the systematic risk is lower than for the petroleum activity due to CfD, while at the other hand financial risk is larger due to much higher gearing. If windfarm companies get into financial problems, the losses to oil companies can be substantial even if they are not responsible for the loans. Most financial analysts do not seem to have focus on this fact.

Equinor has an off-balance debt of around GBP 2.5 billion on this project alone, and with their windfarm ambitions the overall debt will be huge. If we assume that decommission cost is 25% of Capex, there is an additional off balance decommission obligation for Equinor of GBP 0.9 billion on

---

[15] Return on average capital employed, RoACE, is defined as net income adjusted for minority interests and net financial items (after tax) as a percentage ratio of average capital employed, where capital employed is the sum of shareholders' funds and net interest-bearing debt.
[16] Strictly speaking, from an accounting terminology perspective it is not correct to denote this as off-balance debt. The correct term is net presentation. The debt is on the balance, but it is deducted against assets so that gross debt is not visible in the balance sheet.
[17] https://www.ifrs.org/projects/work-plan/equity-method/

this project. Equinor has ambitions for profitable growth within renewables and expects a production capacity of 4-6 Gigawatts (GW) by 2026 and 12-16 GW by 2035[18], and later updated it to 2030. This seems to be a moving target. Let us make a rough calculation on the need for debt if the target is set to 20 GW, or an increase in capacity of 16 GW. For Dogger Bank, the Equinor share of the capacity is 1.28 GW, i.e., the debt is about GBP 2 billion per GW. Thus, to achieve the target of an added production capacity of 16 GW would by a crude estimate entail an added off-balance debt of GBP 32 billion. Analogously, the off balance decommission commitment would be GBP 11.3 Billion.

Off balance debt is regulated by IFRS 11, IFRS 12 and IAS 28. The equity method for accounting is applicable if Dogger Bank is organised as a joint venture and formally and actually is an independent unit. It is our understanding that this is the case. Accounting rules prescribe that investors in an oil company that have equity shares in SPVs get sufficient information on off balance debt. The advantage of SPVs is that investors, if they are properly informed, can access the accounts of the SPVs, at least this is the case in the UK.

By the same crude method, we can calculate the need for equity that Equinor has according to its new goals for windfarm production capacity. Here we need to account for funds the company receives when it sells equity shares to other companies, often referred to as farm-outs. The Dogger bank Capex is GBP 9 billion, of which Equinor holds 40%. If we set the debt to 70% and deduct the combined farm-out payment from ENI of GBP 276.4 million[19], Equinor has to put up an equity of GBP 0.80 billion on this particular project. The Equinor share of the capacity is 1.28 GW, so it took an equity of GBP 0.63 billion per GW. Let us assume that the project is representative, that the company today has a production capacity of 4 and wants to increase it to 20 GW. That would take an added equity of GBP 10 billion. This is a very crude calculation, the point is merely that the need for equity is high and it would probably come out of the cash flow from petroleum activity, leaving less room for petroleum investment. The estimate presumes 70% debt. The need for equity will be higher since the developers are 100% equity financed in the development phase.

There are indications that the farm-out strategy, i.e., the strategy of making a gain when farming out parts of windparks after the de-risking achieved by the completion of the development phase, is under pressure. In the section “Risk and risk management” in the 2020 annual report, Ørsted list interest rates as the top business risk: “Our farm-down model of funding future wind farms through

[18] https://www.equinor.com/en/news/20201102-emissions.html, downloaded 210221, 16:54.
[19] https://www.equinor.com/en/news/20210226-dogger-bank-eni.html
https://www.equinor.com/en/news/202111-dogger-bank-c.html

divestments is exposed to interest rate risks as wind assets are more attractive to buyers when interest rates are low compared to other financial assets with similar risk profiles.”

5. Tax and regulatory charges

Tax depreciation (referred to as capital allowances in the United Kingdom) is given at 18% using the declining balance method. The tax rate is reduced to 17%, effective from 2020. In addition, according to IAE (2018) there is an income royalty fee to the crown of 1% of gross wind farm revenues. Offshore wind regulatory charges in the United Kingdom also include onshore transmission network use of system. Location-based charge levied by National Grid on wind farm owners based on proximity to demand, currently ranging from roughly £0 to £20 per kilowatt per year. There are also charges for balancing services. The charge is levied on wind farm owners by the Office of Gas and Electricity Markets to recover the cost of balancing system supply and demand. The amount charged varies on a half-hourly basis, but the same tariff is charged to all grid users.

For the Dogger Bank project, we do not have access to the capex cost split between wind turbine generators and transmission. For previous projects where we have studied the accounts, e, g., Sheringham Shoal and Dudgeon, we find that the transmission part is about 20% over overall capex. By UK regulation, the transmission asset is transferred to third-party offshore transmission operators (OFTOs), by means of an auction, within 18 months after commission (unbundling, for competition purposes). The final amount is set by Ofgem. The transmission Capex is then refunded to the developers, that instead pay transmission fees. This could be perceived as a sale-and-lease-back arrangement. If the interest used in the lease-back arrangement is equal to the loan rate of the developers, NPV would be unaffected. Financially speaking, it would just be to replace one loan with another. However, the infrastructure investors are likely to demand a profit, so this compulsory arrangement is likely to represent a loss for the developers. We have not accounted for this in the project analysis. In the NPV analysis we assume that the leasing payment is not included in Opex, as this would represent double counting of transmission cost. However, IEA (2018) writes: “The OFTO receives a revenue stream from National Grid, who in turn charges the wind farm owner an offshore transmission network use of system fee to recover the majority of the costs, with the balance of costs being socialised among all users across the wider transmission system.” This could be interpreted as the developers will not carry all the transmission cost. The unique UK system for transmission investment, presents challenges for analysts. Aldersey-Williams et al. (2019) point out a potential problem of double counting of transmission cost, i.e., accounting for full Capex as well as the lease payment.

In our project economics calculations we assume, since we do not know the details of these charges, that the above regulatory charges are offset by any gain possibly arising from the sale and leaseback of the onshore transmission facilities installed by the project. As such, we might slightly overstate or understate the economics of the project, however, to a small degree.

6. Case analysis

6.1 Description of Dogger Bank wind farm

The windfarm is located 130 – 190 km from the North East coast of England.[20] SSE renewables, the development operator, started developing the windfarm in January 2020. Equinor is operations operator. It is owned by SSE Renewables (40%), Equinor (40%) and ENI (20%). UK government expects 60% local content, e.g., UK-based North Star Renewables were awarded the contracts for delivering three service operation vessels (SOVs).[21] The Dogger Bank project with its combined capacity of 3.6 GW is expected to produce enough energy to power the equivalent of 6 million UK homes, or approximately 5% of estimated electricity generation in the UK.[22]

6.2 Project cost

Academic research may shed some light on cost estimation of Dogger Bank windfarm. Developing windfarms further offshore could give a higher rate of energy harvesting and thus higher revenue (Morthorst and Kitzing, 2016). On the other hand, with the windfarm situated far from shore, 130-190 km, would – all things equal – indicate higher LCOE (Myhr et al., 2014). Morthorst and Kitzing find that, unlike onshore windfarms, capex per MW in offshore windfarms has increased in the period 2000-2014, in spite of increased size and expected economies of scale. The authors ascribe this to increasing distance to shore and increasing water depths. Another cost driving factor mentioned is supply bottlenecks and increasing component prices. Aldersey-Williams et al. (2019) also find a substantial increase in UK offshore Capex per MW for windfarms, but with a trend of falling cost in recent years.

[20] https://doggerbank.com/ Downloaded 180221, 11:13
[21] https://www.equinor.com/en/news/contracts-awarded-for-state-of-the-art-service-operation-vessels.html
[22] https://www.equinor.com/en/news/2019-09-19-doggerbank.html, downloaded 2701 21, 13:30.

Morthorst and Kitzing (2016) undertake multivariate regressions on Capex per MW. They apply a database consisting of 45 large European offshore wind parks. The data compiled from 4C, Risø DTU and KPMG constitutes 96% of offshore wind capacity by 2013. Morthorst and Kitzing find that a long distance to shore increases both Capex and Opex. They find that a 10% increase in either distance to shore or water depth gives a 1% increase in Capex. The coefficient for water depth is determined and statistically significant, but due to multicollinearity between distance to shore and water depth, they are not able to separate the two effects. For most wind farms far from shore this would not pose a problem, since they also would be on large depth. For Dogger Bank, this represents an analytical problem since it is on relatively shallow waters. In Figure 2.7 in Morthorst and Kitzing (2016), offshore windfarms are displayed according to water depth and distance to shore. The depth of Dogger Bank of 20-35 metres corresponds to a distance from shore in the range 10-80 km. The windfarm farthest ashore, at 100 km, has a depth of 40 meters. Clearly, Dogger Bank at 130-190 km from shore has a relative advantage of shallow water. Morthorst and Kitzing find that the average distance to shore of the 45 largest European windfarms is 18.8 km, so Dogger Bank really stands out in this dimension.

The average depth of the 45 largest European windfarms is according to Morthorst and Kitzing 15 m. Water depth at Dogger Bank ranges from 20 m to 35 m. This is not particularly deep in general and must be considered shallow this far ashore. According to Morthorst and Kitzing it is usually the case that the farther from shore, the deeper the waters. Dogger Bank is here an exception, so foundation cost will be relatively low. However, Morthorst and Kitzing find that installation and grid connection cost increases with the distance to shore. Installation cost goes up due to tougher weather and more downtime. EEA (2009) estimates a downtime of 20-30% for offshore operations. Increased length of the export cable increases grid connection cost. For Dogger Bank, due to the long distance to the onshore grid connection point, it will require a transmission system with High Voltage Direct Current (HVDC).[23] This will imply added cost. The world's longest edge-to-edge distance of 260 km (Ng and Ran, 2016) may also have cost implications for Dogger Bank.

Dogger Bank has a relatively high number of wind turbine generators (300 12 MW wind turbine generators according to the initial plan, later changed to 190 13 MW wind turbine generators for Dogger Bank A and B, and C yet to be determined), which all things equal calls for lower LCOE (Myhr

[23] "Equinor wins opportunity to develop the world's largest offshore wind farm", press statement September 20, 2019; https://www.equinor.com/en/news/2019-09-19-doggerbank.html. Downloaded 10.12.20 13:45

et al., 2014). A crucial factor to reduce cost is the record turbine size of 13 MW and the fact that it is

the world's largest offshore wind park. The sheer size allows for larger specialised support and maintenance vessels to operate solely in the wind farm (Myhr et al., 2014). For this particular windfarm the wind turbine generators are so high that they have contracted the building of a specialised vessel. This is probably more costly than chartering standard vessels. According to Aldersay-Williams et al. (2019), larger turbines allow more installed capacity per foundation and therefore offer economies of scale in manufacture and installation. Morthorst and Kitzing (2016) point out that some cost components are largely independent from size, thus generating economies of scale. Economies of scale in operation cost is also possible with a higher number of turbines, as the maintenance cost of a turbine is to a large extent determined by access cost. More efficient operational strategies are also open for large windfarms, e.g., by vessels readily available within the windfarm that may give higher reliability and production. EEA (2009) finds that previous reductions in wind energy generation costs were mainly derived from larger turbine capacity. IEA (2018) finds that increasing the turbine rating - while keeping overall wind farm capacity unchanged – cuts cost by reducing the number of array cables and foundations that need to be installed, and by reducing the expected project management cost.

The ground-breaking Dogger Bank project exhibits a combination of complexity, new technology and a very large scale. These are elements that in other industries are clear warning signs for cost overruns (Dahl et al., 2017; Lorentzen et al., 2017). Expected cost reductions from an increase in turbine capacity beyond the planned 12MW remedies this picture. The same goes for the fact that the operation operator Equinor has experience with HVDC-projects from Norwegian petroleum projects where petroleum platforms are run by hydro power from shore.[24]

Sovacool et al. (2017) performs a bivariate analysis of cost overruns in 51 offshore and onshore windfarms commissioned between 2000 and 2015 in 13 countries. The data was generated from academic databased and internet sources. They find that cost of offshore wind increased significantly since the mid-2000s, contrary to expectation and onshore wind. They also report increase in operation cost. Sovacool et al. suggest harsher conditions as part of the explanation, e.g., with larger rotors developed for offshore wind farms, blades and nuckels are exposed to corrosive conditions and greater loads. The conditions lead according to the authors to unique maintenance requirements for offshore turbines having 100,000 components, compared with between 50,000

[24] https://www.equinor.com/en/news/2018-10-09-johan-sverdrup-powered-shore.html

and 80,000 for onshore turbines. Offshore turbines are less standardised. The construction structure via subcontracting for the offshore wind turbine generators is more complex than onshore and can involve more than 50 separate contracts. Moreover, sea and weather conditions can impact availability.

Sovacool et al. find a mean cost overrun of 9.6% for offshore wind farms, considerably larger than for onshore windfarms. Offshore windfarms both have more frequent and larger cost overruns. They document learning effects for onshore but not for offshore windfarms. Further, they argue that the extent of overall risk increases with larger turbines installed further from shore and in deeper waters. Inappropriate weather conditions are given as one of the major risks. However, they do not find a significant correlation between overruns and the size of a windfarm, and they suggest potential explanations that these windfarms typically are developed by experienced companies.

Dogger Bank is a megaproject, by all standards. In other industries, megaprojects face larger overruns, see Flyvbjerg et al. (2003). Dahl et al (2017) find that project size is a significant explanatory factor for cost overruns for petroleum projects, although somewhat difficult to distinguish from project complexity. Reasons given are that megaprojects are difficult to administrate and coordinate, the developers may not have sufficient competent personnel to take on the project, and the project may be so large that it puts a strain on input prices in local or segmented supply markets. We should point out that the size of Dogger Bank is far outside the size of the windparks studied by Sovacool et al. The average windfarm in their study had a capacity of 220 MW, or merely 6% of Dogger Bank. The operations operator Equinor has extensive experience in large offshore petroleum projects. Still, Dogger bank is bigger, it is twice as big as some of the largest petroleum projects, but probably simpler in terms of technology, the number of participants, contract complexity etc. Dogger bank is much larger than the previous offshore windfarm projects developed. We do not have information about the experience of SSE Renewables, the development operator, related to recent development of mega offshore windfarm projects.

Scarce capacity and bottlenecks in the supply chain is a well-documented cause of cost overruns (Lorentzen et al., 2017) and have been an issue in offshore windfarm cost overruns. To ascertain the extent of this problem one needs to check the volume of projects under development in the following years, locally and globally, compared with available supply capacity. The development of Dogger bank will partly overlap with another giant offshore UK windfarm, the 3.1 GW East Anglia

Hub.[25] In addition, COVID-19 may impose some restrictions on the initial stages of the development project.

Experience of the developer company has bearing on the expected cost performance. The operator of the development phase is SSE Renewables. The company is a substantial owner and operator of offshore wind, and a big player in the UK electricity market, but we are uncertain as to recent experience with project development. We checked the UK windfarms analysed in Aldersey-Williams et al. (2019), with production start 2003-2017, and could not find SSE Renewables. We have also checked the 4C database and done internet search and did not find major offshore windfarm development projects headed by SSE Renewables. However, tracking operators on windfarms organised as SPVs is demanding, and we may have missed relevant information. In a report on UK offshore wind industry from 2020, Wood Mackenzie states that "Key players include UK-based SSE, one of the most active wind developers and operators in the region".[26] Wood Mackenzie may have access to more information, or they refer to projects that are not recent.

The operations operator at Dogger Bank, Equinor, was responsible for developing three of the recent UK windfarm projects, as we understand with successful project management. Equinor has seconded personnel to the development organisation of Dogger Bank. The last project developed by Equinor in the UK, Dudgeon, developed between 2012 and 2017, was delivered on time and below cost.[27] Situated 32 km off the coast, it was at that time the windfarm furthest away from the coast.[28] No company has experience with a windfarm project 130-190 km from the shoreline, but Equinor has developed many large petroleum projects that are more complex and farther from shore. Still, it is SSE that is operator of the development phase, not Equinor. Experienced companies have been selected for the transmission job. ABB will supply the HVDC Light® converter systems, while Aibel will deliver two HVDC offshore converter platforms.[29] The companies have experience with such technology from, e.g., power from shore projects to petroleum projects in Norway, working for Equinor, and these projects have generally been on time and below cost.

Cost overruns are to some extent borne by the suppliers, according to the contract terms. From industry sources and reports we learn that vendors of windfarms provide a five-year warranty,

---

[25] https://www.cnbc.com/2021/02/03/siemens-energy-unit-picked-to-install-turbines-at-offshore-wind-hub-.html. Downloaded 030221, 09:05

[26] https://www.woodmac.com/news/opinion/offshore-wind-propels-the-uks-net-zero-ambitions/ Downloaded 04022021 12:53.

[27] https://www.equinor.com/en/news/21nov2017-dudgeon-opening.html

[28] http://www.dudgeonoffshorewind.co.uk/ Downloaded 05012021 12:34.

[29] https://new.abb.com/news/detail/40970/abb-wins-one-of-its-biggest-ever-contracts-to-connect-worlds-largest-offshore-wind-farm-to-uk-grid Downloaded 09012021 16:40.

contingent on a service agreement. Contracts are never complete, and windfarm developers may still end up paying parts of added cost in the warranty period. This seems to be the case for Ørsted, that is repairing hundreds of wind turbine blades, since after a few years the leading edge of the blades has worn down.[30] Generally, suppliers do not carry the cost of downtime, which often may be substantial.

Ørsted has announced that up to ten of its offshore windfarms will need urgent repairs because their subsea cables have been eroded by rocks on the seabed, at a cost of GBP350 million over two years.[31]

From industry experts we learn that they expect that wind farms will have to replace gear boxes and main shaft bearings. These are exposed to high tensions and salt. The replacement cost will be high and downtime considerable.

We have used the original Capex-estimate based on 12 GW turbines in our base estimate. The project is using larger turbines. This may give cost reductions in terms of fewer foundations and less cabling.

6.3 Electricity production

Estimating output from windfarms is not straight forward. First, we need an estimate of how much energy the turbines can extract from the wind. Such calculations lie behind the estimated capacities of the turbines at Dogger bank, in the range 12-14 MW. Second, we need to estimate how large fraction of the time the turbines reach 100% of the capacity, which is denoted capacity factor. Third, we need to adjust for downtime and transmission loss.

The turbines to be installed at Dogger bank has a power capacity of 13 MW. The power capacity of a wind turbine describes how much electrical power a wind turbine can generate with optimal wind resources.[32] However, the speed and consistency of the wind changes over time, and there are days with no wind. Thus, to obtain actual electricity generation from the windfarm we need to multiply by the capacity factor, defined as the electricity production actually generated during a period of time (usually a year), divided by the optimal output a generator can produce when it operates at

[30] http://www.windaction.org/posts/47883-siemens-sets-billions-orsted-must-repair-hundreds-of-turbines#.YBf4huhKjpC. Downloaded 01.01.2020, 13:53.
[31] https://amp.theguardian.com/business/2021/apr/29/rsted-says-offshore-uk-windfarms-need-urgent-repairs?__twitter_impression=true&s=09

[32] https://www.luvside.de/en/capacity-factor-wind-turbine/

ideal state for the same time period (Neill and Hashemi, 2018). Usually, the metric also accounts for downtime.

The press release by Equinor on the Dogger wind farm does not mention the capacity factor. The Dogger Bank homepage refers to a capacity factor of 63%, way above recent UK windfarms. IEA (2018) reports that the average capacity factor for UK windfarms being commissioned in 2017-2018 is 42.3%. Being new windfarms, these are expected capacity factors. Following the approach of Aldersey-Williams et al. (2019), estimated capacity factors for developed windfarms could be checked against production numbers in financial accounts. With this approach, we find that Dudgeon has an actual capacity factor a few percentage points above the reported average capacity factor. Thus, the capacity factor at Dudgeon has reached the highest capacity factor we have found in the literature - 45%. The improvements over time have come in small steps. The crucial question is whether a one-off leap in capacity factor to 63% - a 40% increase from Dudgeon - is reasonable. Probably not. The number quoted is hardly a realistic annual capacity factor for the given location, but rather a potential. This is confirmed by checking the GE homepage for their description of the Haliade-X offshore wind turbine that is selected for the project. They indicate a capacity factor of 60-64%, defining the term as "how much energy was generated against the maximum that could have been produced at continuous full power operation during a specific period of time". Later they state that "One Haliade-X 14 MW turbine can generate up to 74 GWh of gross annual energy production, which equals a capacity factor of 60-64%." Our calculation shows 60.2%[33], only slightly lower than the capacity factor of up to 60.88% of the new 15 MW Vestas turbine.[34] We infer from this that the Dogger Bank homepage has taken its estimate from the GE test. Thus, it is not a reasonable estimation on the capacity factor for the specific windfarm. According to industry sources, tests undertaken by producers are typically done with a single wind turbine generator, and over a short period of time. This is not a transparent process, open for review by independent experts. A group of highly trained personnel is fine-tuning the process, and the reports may be selective as to the choice of time period for testing. Equinor tested five floating wind turbine generators (Hywind Scotland, 6MW), reporting a capacity factor of 65% in the three first months of operation. The months were November-January, and DNV GL (2019) argues that the reported number must be seen in combination with the high-wind period, indicating that the reported capacity factor would not be representative for the annual figure. DNV GL adds that "[…] the load factor level is comparable to that of the Dudgeon project, which uses the same turbine, located off

[33] $\frac{74GWh}{14MW \cdot (24 \cdot 365) \cdot \frac{1}{1000}} = \frac{74GWh}{122.64GWh} = 60.23\%$

[34] https://cleantechnica.com/2021/02/12/vestas-unveils-worlds-most-powerful-offshore-wind-turbine/

the UK east coast during the same time period.” To get information on annual production, we follow the approach of Aldersey-Williams et. al (2019), i.e., we checked the actual annual capacity factor of the Dudgeon windfarm, using production numbers from the annual accounts. We find that annual production was 1579 GWh in 2018 and 1584 GWh in 2019. With a capacity of 402 MW, this gives a capacity factor of 44.8% in 2018 and 45% in 2019. During the Summer months the capacity factor was below 30%. However, updated information on Hywind Scotland gives an average capacity factor of world record 56% over the first two years of operation[35], indicating a more consistent wind over the year. The question is what this tells us about the expected capacity factor at Dogger Bank. Hywind Scotland, the world’s first floating offshore wind farm, has smaller turbines (6MW) and is closer to shore (25 km), which would indicate that Dogger Bank could reach even higher capacity factor. On the other hand, the advantage of floating wind turbine generators is that you do not rely on shallow waters, the mills can be located at optimal wind conditions. Thus, the location 25 km east of Peterhead, substantially north of Dogger Bank, probably has better wind conditions than Dogger Bank where a key selection criterion probably was shallow waters.

We need several sources and inputs in the attempt to estimate a reasonable capacity factor. A starting point in this evaluation is to examine the characteristics in which Dogger Bank deviate from the average of UK windfarms being commissioned in 2017-2018. The representative windfarm sanctioned in that period has according to IEA (2018) a water depth of 27 m., a distance to construction port of 25 km, a distance to O&M port of 25 km, distance to cable landfall 50 km, a mean wind speed of 9.15 m/s, and a capacity of 414 MW (69 turbines of 6 MW). We do not have access to all these numbers for Dogger Bank. From the data we have, it is clear that Dogger Bank deviates dramatically from UK windfarms sanctioned only a few years ago. While the water depth is about the same, the capacity of the wind turbine generators is doubled (from 6 to 12 MW) and is increasing, the number of wind turbine generators is about three times as high, the overall capacity is more than eight times as high, and the distance to cable landfall is 160% longer. Clearly, output figures from the representative windfarm are not directly applicable in this case. According to Merz (2016), the average wind speed at turbine height is between 8 and 9 m/s at Dogger Bank, which is slightly below UK offshore windfarm average (EIA, 2018). However, farther from shore, the wind may be more consistent.

[35] https://www.equinor.com/en/news/2019-11-28-hywind-scotland-data.html

Equinor refers to "excellent wind speed".[36] Being farther ashore than other windfarms, and using larger turbines than previously, may call for a higher capacity factor. The question is how much. IEA (2018) states that turbine capacity factors are expected to rise the next few years since newer generation turbines are optimised and integrated wind farm control systems improve. BEIS (2020) assumes that GBP/MW Capex and Opex decrease over time as larger size of turbines allows economies of scale. Load factors are also assumed to increase with turbine size as they due to increased height can access stronger wind and as windfarms with fewer and larger wind turbine generators are more efficient. For 2025 they project a turbine size of 12MW and a load factor (net of availability) of 51%, increasing to 15MW and 57% in 2030. They assume an operating period of 30 years for both scenarios, more than the Dogger Bank project assumption.[37] They use a real discount rate before tax of 6.3%. BEIS confirms that the CfD prices on Dogger bank is lower than their own generic LCOE calculations, i.e., that according to their cost calculations the project will have a rate of return below 6% in real terms. However, they add that the project has several features that deviate from the BEIS generic project assumptions, e.g., the wind farm is considerably larger and is likely to have more economies of scale, the wind farm is situated farther from shore and thus has good wind conditions (higher load factor), and not significantly higher construction cost due to shallow water depth. We would add that a location so far ashore may imply more downtime and higher transmission cost. For projects commissioned in 2025 (with turbine size 12 MW), BEIS has a LCOE estimate of 57 GBP/MWh in real 2018 values. A comparable, inflation adjusted average CfD price for Dogger Bank CfD-price is around 46 GBP/MWh. It is comparable to the BEIS cost estimate for projects commissioned in 2030 (turbine size 15 MW), with a LCOE estimate of 47 GBP/MWh.

BEIS (2020) refers to a report they have commissioned, DNV GL (2019). DNV GL estimates a generic capacity factor for next generation wind turbine generators (10-12MW) in the mid-2020s to 50.3%. They remind us that wind farms located far from its grid connection point will require a higher proportion of Capex to be spent on export cabling. They find that higher wind speed increases the capacity factor, but that the site conditions are challenging. We interpret this so that downtime will be higher than average. They mention the GE Haliade-X offshore wind turbines, and comment that the technology is relatively proven and that much of the underlying technology demonstrated in a relevant environment. According to Aldersey-Williams et al. (2019) there is limited opportunity to validate the input data in the BEIS analysis. In a press release from GE from October 2020, we learn

[36] "Equinor wins opportunity to develop the world's largest offshore wind farm", press statement September 20, 2019; https://www.equinor.com/en/news/2019-09-19-doggerbank.html. Downloaded 10.12.20 13:45
[37] The Dogger bank homepage says 25 years, and the press release from Equinor says at least 25 years.

that the Haliade-X 13 MW is an uprated version of the prototype that has been successfully operating in Rotterdam since November 2019.[38] Thus, there is limited operational experience on this wind turbine generator as to the production over the lifecycle. The press release does not contain information on the capacity factor, but it is stated that the uprated version "will be able to generate 4% more energy than before".

Almost 50% increase in the capacity factor over only a few years is not a normal productivity step. In our baseline estimate we set a capacity factor of 55% (net of availability), i.e., we assume 30 % increase from the UK 2017-2018 average. This estimate, that is higher than the capacity factors used in the generic BEIS (2020) and DNV GL (2019) LCOE analyses, is optimistic, representing a world record increase in offshore wind turbine generator productivity. We will use 50% and 60% as sensitivities.

To calculate electricity production, we need to deduct downtime and transmission loss. Preventive maintenance and improved monitoring systems are in place to reduce downtime, but it cannot be fully avoided. Downtime incidents are often positively correlated with bad weather and the duration of downtime therefore increases due to waiting on calmer weather that allows for reparation. The farther the windfarm is from shore, the harsher weather, and the longer distance for the vessels needed for maintenance. Moreover, it may not be economically sound to repair individual wind turbine generators, one might design maintenance campaigns involving several wind turbine generators. Again, this increases downtime. This is referred to as opportunity-based maintenance (Myhr et al., 2014), that allows maintenance of all categories on several turbines simultaneously, thus reducing mobilization cost of external vessels. According to Myhr et al., (2014), "Power output to the grid is substantially less than one can expect from the capacity factor alone. This is due to several sources of loss, such as wake losses, losses on the power electronics and downtime". Myhr et al. calculate capacity factor for a 5MW offshore windfarm with a power capacity factor (PCF) set to 53, with +/- 3% for the high and low sensitivity, with a resulting grid output factor calculated at 44% (net load factor, LF). Thus, the LF in this case was estimated at 83% of PCF. IEA (2018) finds average downtime in UK offshore wind to be 5.13%. From the accounts of Dudgeon windfarm we learn that availability was 95.1% in 2019. We have not accounted for this directly, since our capacity factor estimate accounts for availability.

[38] https://www.ge.com/news/press-releases/ge-haliade-x-offshore-wind-turbine-prototype-operating-at-13-mw

With this approach, we have a basis estimate of the capacity factor of 55%, and with sensitivities 50% and 60%. In addition, correction must according to industry sources be made for transmission estimated to 5% of the electricity produced.

Compared with a representative oil project, wind farm investment often has much shorter lead times. The vast scale of Dogger Bank, and the sequencing of investment, makes this project an exception. From start of investment to finalising development data, it takes six years (investments takes place from 2020 to 2026). However, the first subproject is put in production once it is finalised, so it only takes four years to first production (first production at Dogger Bank A is scheduled to 01 September 2023).

6.4 Electricity prices

After 15 years of production, i.e., in 2038-2040, the Dogger Bank project faces price risk in the final years of production. At this point of time, UK will have a larger fraction of electricity produced from wind, and we may learn something of the price process by reviewing the current Danish electricity market, which in 2018 has more than 40% of total consumption covered by wind energy (Berg et al., 2021). According to Morthorst and Kitzing (2016), offshore wind projects reduce the electricity price in the wholesale market. Ketterer (2014) examines the impact of wind power generation on the electricity price in Germany and find that introduction of variable wind power not only reduces the electricity price, but it also increases its volatility. When volumes of intermittent renewable energy are fed into the grid, more expensive conventional power plants are crowded out, and the wholesale electricity price declines (the merit-order effect). Increased renewable electricity supply, in particular wind, appears to have large effects on electricity prices and occasionally causing zero or negative prices (Berg et al., 2021). In Denmark in 2018 this was according to the authors the case for 1238 hours, or about 14% of the time. It happens when intermittent wind production, that essentially has a zero marginal cost of production, is the marginal source of electricity production. The high level of intermittent production imposes according to Berg et al. large problems for the system operator, to enhance grid flexibility, establish further interconnections and adapt energy storage technologies.

Our price estimation task is at the outset to estimate expected electricity price in UK, from 2038 to 2050. But we cannot simply multiply expected production with expected prices, as this would implicitly presume that the wind production in the project is stable over time. It is not, it varies largely with the speed and the consistency of the wind. So, we must estimate the electricity prices at the times of production. When there is high wind speed, there is high windfarm production and thus low or possibly even negative prices. Having low prices at times of high production is not good for revenue. There is also the issue that the wind speed may be low when it is cold and electricity prices are high (Oswald and Ashraf-Ball, 2008). Thus, electricity prices obtained from wind production will be less than the average electricity price. New supply of wind power reduces electricity prices for all electricity suppliers, but particularly for other wind producers (that are not on a fixed price contract), due to the intermittency of production. This increases the number of days with zero price, referred to as cannibalisation. It may limit the amount of wind capacity one can develop in a market. After a steep increase, electricity produced from wind in Denmark has been fairly stable after 2015 (Hagos and Ahlgren, 2020). The extent of cannibalisation in the British electricity market will depend on several factors. One is the extent of expansion in production from offshore wind. The UK has very high ambitions, they want to increase the offshore wind capacity to 40 GW by 2030 and 100 GW by 2050. These plans are carried out, the fourth round of the CfD-scheme, set to open late in 2021, aims to support up to 12 GW.[39] At the end of 2019 the capacity was 8.6 GW. A key question is to what extent this can be remedied by increased demand and enhanced system flexibility, e.g., in developing transmission infrastructure in the short run and energy storage in the long run.

We assume that the developers are not able to get a power purchase agreement for intermittent power production at competitive terms for the years after the CfD-contract has expired. With an expected large influx of wind power, the UK electricity prices may be reduced if the increase in demand and system flexibility do not keep the same pace. Thus, the current Danish electricity market, with a high propensity of wind power, may be an indication of where the UK is heading. Our selected price estimation approach for the lower range is thus to use the inflation adjusted average Danish electricity price for the last three years, to use as expected UK electricity price for 2038-2050. The Price series is Nord Pool Spot, for dk 1 and dk 2. We use the inflation adjusted average UK electricity price for the last three years as an estimate for the high range. We set the expected price as the average of the two. We multiply the prices by an adjustment factor less than one, accounting for the value difference between intermittent offshore windpower and the general electricity market. We set the factor to 0.9. Inflation adjusted average for Nord Pool spot, dk1 and dk2, for 2018-2020 is 38.96 GBP/MWh. Inflation adjusted average for the UK spot price for last three years is 71.86 GBP/MWh. The average of the two is 55.41 GBP/MWh, and 49.87 GBP/MWh after multiplying with the factor 0.9, the intermittency wind power discount. Below in Table 1 we summarize the effects of our assumptions on before tax cashflows.

[39] https://www.gov.uk/government/collections/contracts-for-difference-cfd-allocation-round-4

Windfarm revenue scenarios (nominal) (before royalty to crown 1% and transmission loss 5%)				Wind farm expected capex and Opex	
Year	Expected	High	Low	Capex	Opex
2020				1000	0
2021				2040	0
2022				3121	0
2023	281	281	281	2122	32
2024	588	588	588	1082	68
2025	907	907	907	0	106
2026	925	925	925	0	114
2027	943	943	943	0	121
2028	962	962	962	0	129
2029	981	981	981	0	137
2030	1001	1001	1001	0	145
2031	1021	1021	1021	0	153
2032	1041	1041	1041	0	162
2033	1062	1062	1062	0	171
2034	1083	1083	1083	0	181
2035	1105	1105	1105	0	190
2036	1127	1127	1127	0	200
2037	1150	1150	1150	0	210
2038	1206	1206	1206	0	221
2039	1246	1246	1246	0	232
2040	1286	1286	1286	0	243
2041	1312	1312	1312	0	255
2042	1338	1338	1338	0	267
2043	1365	1365	1365	0	280
2044	1392	1392	1392	0	292
2045	1420	1420		0	306
2046	1448	1448		0	319
2047	1477	1477		0	333
2048	1507	1507		0	4265
2049	0	1537			
2050		1568			
2051		1599			
2052		1631			

Table 1. Summary of revenue scenarios and cost assumptions (nominal million GBP); for production periods of 20, 25 and 30 years.

6.5 Project economics

The basis for the inputs to the project economics is presented in table 1. We use 25 years as expected production period and we also provide calculations for a low and high scenario with respect to project production life. Our production scenarios are assuming a capacity factor of 55% (net of availability). In the income stream, adjustment must be undertaken for the transmission loss assumed to be 5% of the electricity production. Baseline Capex is GBP 3 billion per project, in total

9 billion GBP 2020. Decommissioning cost is set to 25% of Capex and we assume a gradual increase in OPEX as the installations get older. Given the electricity price for the fixed price period and the estimated 49.869 GBP 2020/MWh after 2038, the project economics is presented in Table 2.

All cashflow in million GBP	Cashflows								
	Before tax	After tax							
	Nominal Total Capital	Nominal Equity Capital	Nominal Total Cap. (WACC)	Nominal Total Cap. Ardit/Levy	Nominal Debt Capital	Discounted Total Cap. (WACC cf)	Payback Year 2036	Nominal Equity Cap. 100% removal	Payback Year Equity 2035
IRR	6,0 %	6,1 %	5,6 %	5,8 %	4,8 %	(5,9%, 8,5%)*		5,8 %	
Year/NPV	-1 725	-1789	-1789	-1789	0	-970			
2020	-1000	-1215	-969	-969	246	-969	-969	-1 215	-1 215
2021	-2040	-1378	-1952	-1954	-577	-1 843	-2 922	-1 378	-2 593
2022	-3121	-2053	-2954	-2951	-898	-2 633	-5 876	-2 053	-4 646
2023	-1890	-1153	-1728	-1718	-564	-1 454	-7 604	-1 153	-5 800
2024	-598	-252	-481	-466	-214	-382	-8 085	-252	-6 052
2025	746	646	782	800	154	587	-7 302	646	-5 406
2026	756	629	761	778	150	539	-6 541	629	-4 777
2027	766	616	745	762	147	498	-5 795	616	-4 161
2028	776	606	734	750	145	463	-5 061	606	-3 556
2029	786	598	726	742	144	433	-4 335	598	-2 958
2030	796	592	722	737	145	406	-3 614	592	-2 365
2031	807	588	719	734	146	382	-2 894	588	-1 777
2032	817	585	719	734	148	361	-2 175	585	-1 192
2033	828	584	720	735	151	341	-1 455	584	-608
2034	838	583	723	737	154	323	-732	583	-25
2035	849	582	727	740	158	307	-5	582	557
2036	860	582	732	744	163	292	727	582	1 138
2037	871	582	738	750	168	278	1 465	582	1 720
2038	913	600	770	781	181	176	2 236	600	2 320
2039	939	608	790	800	192	166	3 026	608	2 928
2040	966	616	810	819	203	157	3 836	616	3 544
2041	979	616	819	827	211	147	4 655	616	4 160
2042	991	615	828	835	220	137	5 483	615	4 775
2043	1004	613	838	843	230	127	6 321	613	5 388
2044	1017	611	848	851	240	119	7 169	611	5 998
2045	1030	608	858	859	252	111	8 027	608	6 606
2046	1043	604	868	867	264	103	8 895	604	7 210
2047	1056	599	879	876	277	96	9 774	599	7 808
2048	-2848	-1678	-2354	-2360	-682	-237	7 419	-2 360	5 449

*Nominal discounting in fixed price period (through 2037) and market exposed prices period respectively

Table 2. Expected project economics of Dogger Bank wind farm.

Table 2 shows the results of project economics with the before tax and after tax cashflows. In addition, the debt cashflow and the discounted cashflow with the fixed price discount rate (5,9%) and the market exposed discount rate (8.5%) is presented. A crucial question is whether the decommissioning cost may be project financed with debt, and we also show the equity cashflow given 100% equity financing of decommissioning cost. In the table we also show payback on the total capital stream and the equity capital stream. As the results demonstrate, the expected NPV is a negative 1789 million GBP and equal for the total capital cashflows and the equity cashflow when using the correct required returns in discounting. Using a separate discounting of the total capital cashflow according to the price risk in the two price regime periods gives a NPV of a negative 907 million GBP. The internal rate of return of the WACC total cashflow after tax is 5.6% (6.0% before tax) and for the equity stream it is 6.1% (5.8% with 100% decommission from equity). Payback is in 2036 and 2035 for the total capital and equity capital cashflows respectively, i.e., a payback-period of 17 and 16 years. The farm-out to ENI in February 2021, assuming payment of 405MGBP in 2022 for a 20% stake in A and B phase of the project[40], would imply an estimated increase in the IRR of total cash flow to 6.2%, nominal. For ENI this acquisition would yield an estimated IRR of total capital invested of only 2.7%. After the second farm-down to ENI in November 2021, a 20% interest in phase C for GBP 140 million, expected IRR for SSE and Equinor increases to 6.4% nominal, and ENI is expected to get 2.9% nominal. The payment in the second farm-out was 30% lower per MW.

We now turn to examine the sensitivities of the project to changes in the actual outcome of the most relevant risk factors of the project. These are illustrated in the sensitivity table below.

All cashflow in million GBP	Cashflows Before tax	After tax								
	Nominal Total Capital	Nominal Equity Capital	Nominal Total Cap. (WACC)	Nominal Total Cap. Ardit/Levy	Nominal Debt Capital	Discounted Total Cap. (5,9%, 8,5%)*	Payback Year	Nominal Equity Cap. 100% removal	Payback Year Equity	Project sensitivity
IRR, payback	4,7 %	4,5 %	4,4 %	4,6 %	4,8 %		2037	4,1 %	2036	**Capacity -5%**
Year/NPV	-2 451	-2392	-2392	-2392	0	-1 690				
IRR, payback	7,1 %	7,6 %	6,7 %	6,9 %	4,8 %		2034	7,4 %	2033	**Capacity +5%**
Year/NPV	-999	-1186	-1186	-1186	0	-251				
IRR, payback	7,8 %	8,5 %	7,3 %	7,5 %	4,8 %		2034	8,3 %	2032	**Investments -15%**
Year/NPV	-471	-694	-694	-694	0	163				
IRR, payback	4,5 %	4,2 %	4,2 %	4,3 %	4,8 %		2037	3,8 %	2037	**Investments +15%**
Year/NPV	-2 980	-2884	-2884	-2884	0	-2 104				
IRR, payback	6,8 %	7,2 %	6,4 %	6,6 %	4,8 %		2036	7,0 %	2034	**Price +20%**
Year/NPV	-1 290	-1428	-1428	-1428	0	-609				after 2037
IRR, payback	5,0 %	4,8 %	4,6 %	4,8 %	4,8 %		2036	4,4 %	2035	**Price -20%**
Year/NPV	-2 160	-2150	-2150	-2150	0	-1 332				after 2037
IRR, payback	6,4 %	6,7 %	6,0 %	6,2 %	4,8 %		2035	6,5 %	2034	**Opex -20%**
Year/NPV	-1 455	-1565	-1565	-1565	0	-705				
IRR, payback	5,5 %	5,5 %	5,1 %	5,3 %	4,8 %		2036	5,2 %	2035	**Opex +20%**
Year/NPV	-1 995	-2013	-2013	-2013	0	-1 236				
IRR, payback	6,8 %	7,3 %	6,5 %	6,7 %	4,6 %		2036	7,3 %	2034	**Long life scenario**
Year/NPV	-1 330	-1415	-1415	-1415	0	-643				
IRR, payback	4,5 %	4,2 %	4,1 %	4,3 %	4,8 %		2036	3,7 %	2035	**Shorter life scenario**
Year/NPV	-2 316	-2279	-2279	-2279	0	-1 461				
IRR, payback	6,0 %	6,6 %	5,6 %	5,7 %	3,0 %	(5,47%, 8,09%)*	2036	6,4 %	2034	**3% debt financing**
Year/NPV	-1 476	-1572	-1572	-1572	0	-698				included in WACC
IRR, payback	6,0 %	13,1 %	5,6 %	5,9 %	3,0 %	(4,06%, 5,48%)*	2036	12,6 %	2029	**3% debt financing**
Year/NPV	425	79	79	79	0	714				and 70% debt

Table 3. Sensitivities illustrating project economics of Dogger Bank wind farm for other outcomes than expected.

[40] https://www.equinor.com/en/news/20210226-dogger-bank-eni.html

The results demonstrate how project economics may be substantially negatively or positively affected by changes in the expected inputs. Special attention should be given to investment cost, capacity factor, and the length of the production period. The financing sensitivities with 3% interest rate and 70% debt ratio are only provided to illustrate the effect of these assumptions that we believe are common today. We do not recommend these calculations and do not believe they indicate real project valuations. The interest rate is too low for a project with this duration, and the calculation do not account for the fact that higher gearing increases the risk. Note that the far largest figure for return on capital in Table 3 - the nominal equity return after tax of 13.1% with the assumed nominal interest rate of 3% and 70% project financing – is often the figure selected to present profitability of current wind farm projects. With these assumptions there is large variation in Equity return. The effect on equity return with changes in project input may be illustrated with an increase in Capex of 15% resulting in an equity return of 6,9%, while a reduction in the capacity rate of 5% reduces the equity return to 7.6%. In our view the internal rate of return of the WACC total cashflow after tax of 5.6% is the best estimate for the return on total capital for this project.

6.6 Discussion of results

The internal rate of return of the project is 5,6% after tax for the base case. The payback occurs in year 17 of the project. This means that investment is not recouped in the period of fixed price. This is a long payback-time compared to petroleum projects. The average payback-time on investments on the Norwegian continental shelf is according to calculations made for 2000-2019 by the Norwegian Petroleum Directorate 6 years, when also accounting for exploration cost (a full cycle unit cost of 22 dollars per barrel).[41] This figure has come down, Equinor reports payback times of only one and a half years on non-sanctioned projects (not counting exploration cost).[42] That implies that an average petroleum project compared to this particular offshore wind project has a very different dividend capacity. This seems to be a general feature. In the first quarter of 2020 BP announced a 50% dividend reduction as the company looks to ramp up its investment in renewables whilst cutting hydrocarbon generation by 40% through to 2030.[43]

By contrast, the riskiness of income is lower in the fixed contract price period for the offshore wind project. However, the project has a considerable change in risk when the fixed CfD-price ends after

[41] https://www.npd.no/en/facts/news/general-news/2020/profitable-exploration-on-the-norwegian-shelf/
[42] https://www.equinor.com/en/what-we-do/calendar/capital-markets-day-2021.html.html
[43] https://www.cnbc.com/2020/08/05/bp-ceo-says-dividend-cut-deeply-rooted-in-strategy.html

15 years. The developers then face considerable systematic price risk, and the rate of return requirement must reflect this. This fact is often ignored in analyses by investment banks. We have addressed this by using different rate of return requirements for the two project periods in our principal NPV calculation.

An argument against our approach of applying a higher rate or return requirement is that the developers may enter into a power purchase agreement (PPA). A PPA is a commercial or financial contract where a counterparty agrees to a fixed purchase price, which would call for a lower rate of return requirement. It remains to be seen whether this market will have enough liquidity to take on the full volume from this and many other emerging windfarm projects. The terms of existing PPAs are not disclosed. We expect such a price to be at a discount, as the buyers demand a risk premium. In this case the effect on NPV may be similar to our approach, or the value will be lower. Some PPAs for renewable electricity are entered into by companies that will secure their customers use of clean energy. Typically, electricity is not one of the main cost factors for such companies. The electricity mix is expected to be much cleaner in the production period after CfD-price, i.e., 2038-2052, so this type of demand for PPAs is likely to be lower at that time. For companies that have electricity as one of their main inputs, it may be hard to estimate the need for electricity so far ahead. They often demand baseload and must find a way to hedge the balancing requirement related to intermittent wind power. A long-term hedge of this type may also prove challenging if they have competitors that buy electricity in the spot market and spot prices over a period turn out to be low.[44]

The Dogger bank project and Energy-trading company Danske Commodities[45] has signed a 15-year power-purchase agreement (PPA) to trade and balance 480 megawatts of the output from the 3.6-gigawatt Dogger Bank offshore wind farm.[46] We have not found information on PPA for the production period after CfD-prices. The price of the PPA is not disclosed. However, we find an indication of the range of the price discount by scrutinising the accounts for the Dudgeon windfarm. It entered into a PPA for the CfD-period of 15 years.[47] From the revenue statement from Dudgeon windfarm we learn that the price discount in the PPA, relative to wholesale spot price is 16.2% in

[44] An analogy is gas power plants that faced problems with oil-linked gas contracts when the oil price was high and spot gas prices were low. This was one of the reasons why oil-linked contracts were abandoned. There contracts had guaranteed deliveries of natural gas.
[45] The Aarhus, Denmark-based firm was acquired in 2018 by Equinor. https://www.equinor.com/en/news/2019-02-01-danske-commodities.html
[46] https://www.upstreamonline.com/energy-transition/energy-trader-signs-first-power-purchase-deal-at-world-s-largest-offshore-wind-farm/2-1-859008
[47] https://doggerbank.com/project-news/power-purchase-agreements-signed-for-dogger-bank-a-and-b/

2018 and 17% in 2019. PPA-contracts for the CfD-period does not impact our NPV analysis, as the actual revenue to the windfarm is determined by the CfD-price.

The web page of the project sets the production period to 25 years. Aldersey-Williams et el. (2019) write that windparks usually have a 20-25 years operating life, and they use 25. BEIS (2020) use 30 years for windparks with the newest turbines. We use 25 years as the base case but also test for 20 and 30 years. With our basic assumptions, we have enough information to make calculations of the optimal production period. This is determined by the development in the market electricity price versus the development in Opex per KWh. With an increasing Opex over time, it may exceed the electricity price before the projected project period. Closing down may still not be optimal, however, as it would make the large decommissioning cost come sooner. The value of delaying this cost may call for a prolonged project period.

After the end of the production period, wind turbine generators and transmission equipment must be removed. This is to be paid by the owners, according to the agreement with the UK government. Removing a large number of wind turbine generators and their substructure is a huge marine operation under tough weather conditions. The wind turbine generators and the substructures must be transported ashore and treated according to environmental regulations. This is costly. We estimate the decommissioning cost to 25% of Capex. This cost element is often left out in investment bank analyses. It is also ignored in BEIS (2020), with the unreasonable assumption that decommissioning costs is equal to the scrap value of the plant. The decommissioning accounting arrangement is explained in the accounts of the Dudgeon windfarm. The decommission provision is discounted to the balance sheet date at a pre-tax rate reflecting the time value of money and risks specific to the liability. Decommissioning cost are capitalised and depreciated on a straight-line basis over 27 years, starting at the time of full production. From the 2019 accounts of Dudgeon windfarm, we learn that the decommissioning cost is discounted back to present value at a rate of 1.92%. We make a simplifying assumption of tax refund at the time of decommissioning. A questioned raised about decommissioning is whether it could be postponed by re-using the substructures by installing new turbines. According to industry experts this is not a viable strategy since the substructures are not likely to be certified for reuse.

Cost overruns in offshore wind is lower than for other energy infrastructure projects, with a mean overrun of 9.6% (Sovacool et al., 2016), and where the cost overrun is independent of the turbine MW. compared to 25% in Norwegian petroleum projects (Dahl et al., 2017). However, petroleum companies account for this in several ways, e.g., by contingencies in cost estimates, by stress testing of projects, by a high required rate of return, and by demanding a high NPV for sanctioning projects (by low breakeven prices or by a net present value index requirement; Osmundsen et al., 2022). We have not been able to find out how potential cost overruns are handled by offshore wind developers. The question is whether fierce competition over windfarm acreage and CfD-contracts allows developers to adequately account for cost contingencies in budgets. The fierce competition also puts very high pressure on cost reduction among suppliers, that know that to become a supplier they must be part of a winning team. The pressure for cost reductions may become unrealistic. According to industry experts the pressure may lead to EPC contracts terms that are not viable, where suppliers must compensate by more variation orders. This may cause cost overruns in the development projects. We may also see higher Opex than estimated as cost pressure may make it tempting or necessary for suppliers to use parts with lower quality.

Even with lower cost of capital requirements, the project economics is exposed to time overruns. According to Koch (2012), offshore wind projects had an average time overrun of 45% from 2004 to 2008.

A key question is whether the steep reduction in CfD-prices is to be covered by a reduction in Capex and Opex, in a reduction in the return to the windfarm developers, or a combination. With an IRR of total capital of 6.4% nominal after farm-down for the original owners, considerably lower than for previous windparks, we conclude that it is a combination.

Cost reductions in offshore windfarms have been expected over time, so that the LCOE comes down to the level of the market price for electricity. If successful, the Dogger Bank project may be the one to close in on this milestone. The steep reduction in the CfD-price, brought about by fierce competition and cost reductions, has for the Dogger Bank project reached a CfD of about 46 GBP/KWh in 2021 prices, which is below the average UK spot price for electricity. Inflation adjusted average for the UK spot price for last three years is 71.86 GBP/MWh. However, the comparison is a bit more complicated. Since the value of irregular wind power is lower than for baselod supply of electricity, we cannot use the average spot price for comparison. Strike price below average spot price has in media been characterised as a situation without subsidies. We learn from industry experts that new fixed price contracts are not to be expected, offshore wind farms must now expect to face ordinary market prices, like other industries. However, according to Osmundsen and (2022), it is not the case that CfD similar to the market price is a situation without subsidies. The UK government is carrying the initial price risk, offering fixed electricity price the first 15 years of production. If the CfD-regime is to be abolished, the developers would have a higher rate of return requirement and thus require a higher market price. The breakeven price for electricity would now be much higher than current spot price and the CfD-price. The difference between the breakeven price and the current spot price is an indication of the level of subsidy in the CfD-system. Alternatively, the developers may sell the electricity via a PPA and apply a low discount rate. But the

PPA comes with a discount relative to the spot price, due to risk premium to the buyers, which is another indicator of the subsidies in the current system. For the Dudgeon windpark, the discount was 17% in 2019. The developers have an option to select market prices instead of a CfD-price, so we will over time learn more of the trade-offs done by developers if CfD-prices are still offered. This decision will depend on the risk premiums applied by the developers and their expectations for the electricity price.

One might think that a lowest possible strike price would benefit the UK. In the short run, yes, UK would get cheaper renewable energy. In the longer run, if strike prices get so low that it gives low return on investment, it may deter future investment. Currently, the access to capital for offshore windfarm projects is abundant. With very low interest rates, investors are seeking projects that can deliver higher rate of return and that at the same time are perceived as being low risk. Higher interest rates and disappointing returns may change this situation. Department of Business, Energy & Industrial Strategy seems to grasp this point, arguing for a rate of return requirement (6.3%, pre-tax, real) that is higher than the current investment climate indicates. This is also the perspective in IEA (2018), that for UK estimates a 4% interest rate on debt to allow for the consensus that, with interest rates at all-time lows, interest rates in the medium-to-long term are likely to rise. For long-term investment one has to consider long-term interest rates. Even for the low interest period 2009-2019, the US ten-year treasury bond had an average real annual rate of return of 3.1% (data from Morgan Stanley, via Bloomberg).

The US 10-year treasury rate has been increasing since August 2020, and expansive fiscal policies in 2021 are expected to drive the interest level further up. With high gearing there is high risk exposure related to an increase in interest rates. Dogger Bank windfarm has low margins, a locked-in power price for the first 15 years, and long duration. Thus, it is very exposed to an increase in interest rates. Accordingly, banks normally require part of this this exposure to be secured. Similar risk applies to the rising concern over steeply increasing price of raw materials, like steel. The effect depends on the extent that project developers have signed development contracts and the extent these contracts protect against increases in prices of raw materials.

7. Conclusions

The oil companies' investment in windfarms so far seems to be independent of the business cycle in the petroleum industry. When the combined effect of COVID-19 and oil price war brought a steep fall in the oil price in 2020, windfarm investments were not delayed but followed the original plan. This is a welcome feature of this market segment for the supplier industry, that needs regularity in assignments. Possible explanations are that the activity is a response to specific targets set by the oil companies, that large parts of the funding is off balance debt in SPVs, and that funds for windfarm investment have so far been abundant. The fixed income from windfarms, in the period of CfDs, may prove a stabilising factor in oil companies facing a shifting cash flow due to a volatile oil price. At the same time, commitments to fund the windfarm expansion may curb investments in petroleum activity, as communicated clearly by BP and Shell, and indicated by Equinor.[48] The equity commitments can be covered by reduced dividends, assets sales or reduced petroleum project investments. As illustrated by the Dogger Bank case, the payback time of this type of investment is very long, making it hard to fund new investment from free cash flow, unless significant farm-outs are undertaken. Adding to this bleak liquidity situation is the fact that lenders that are putting up 70 % of the funding require payback of loans in the period of fixed prices. This raise concerns over the dividend capacity of oil companies with a large and increasing fraction of investments in windfarms as well as over the capacity to fund windfarm investment. This may provide a background for the dismissal of Total of cutting back the petroleum activity and of denying splitting off its renewable arm as a separate listed company, believing its clean energy business will still need the financial support provided by oil and natural gas.[49] When European oil majors go with the trend of reallocating investment from oil projects to windfarms, they are likely to see that the relative prices of oil and electricity move in their disfavour. Irrespective of accounting policy selected, this implies lower return on capital and weakened dividend capacity.

Low profit margins reduce the potential for the offshore windfarm industry to be a driver for the Norwegian supply industry. This problem is reinforced by local content requirements imposed in many countries, e.g., the UK sector has set a target of 60% lifetime UK content in domestic projects

---

[48] https://www.upstreamonline.com/energy-transition/equinor-to-increase-renewables-investment-despite-rising-oil-prices/2-1-960755
https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/investors/bp-annual-report-and-form-20f-2019.pdf
https://www.upstreamonline.com/energy-transition/shell-to-oversee-gradual-managed-decline-of-oil-output-van-beurden/2-1-961576?s=09

[49] https://www.ft.com/content/0d3c0ea1-2643-4ceb-90ed-961d51f8123d?shareType=nongift

(up from the current 50%) and targeting increasing UK content in the capital expenditure phase.[50] At any rate, the offshore wind industry does not seem labour intensive. UK, that has half the European capacity of offshore wind and that has succeeded in sourcing almost 50% of the projects' content to the UK, only 7,200 jobs are associated with the industry (HM Treasury, 2020).

Project calculation of the scheduled Dogger Bank windfarm proved to be a daunting task. Such a calculation rests on a large number of uncertain input factors of which few are available. By doing a fully transparent analysis, where we set up the decision problem at each of the input parameters are discussed and related to available data and academic literature, we believe that the paper contributes by enlightening project economics of a current offshore windfarm. We use ranges for the input parameters and find the value range of the project for critical input parameters. We find that the most critical input parameters are capacity factor, the rate of return requirement and the electricity price for the production period after the CfD-price.

IEA (2018) finds that return expectations in offshore windpower is decreasing due to increased competition through auctions. Owners of recently sanctioned windfarms stand according to industry sources to generate a nominal return of 5 to 6%, and fierce competition is expected to press it down towards 4-5%. Pioneering investors in offshore wind, Danish pension funds, are now divesting, stating that their returns in the sector have gone from 8% to 4-5%, which is considered lower than their rates of return requirements.[51] Thus, return expectations are below the IEA (2018) real estimated rate of return requirement of 6,55% and the BEIS (2020) nominal requirement of about 8%. Still, large offshore windpower investors like Ørsted and Equinor state return targets way above the expected return levels for new windfarms. For instance, Equinor states a target of 4-8 % real return on this activity.[52] The higher part of the interval is probably relating to projects in immature markets and with farm-outs. So far, they have been able to achieve this type of return, in fact even higher levels. The recipe of success has been to enter early into an immature market, benefit from cost reductions stemming from increased turbine capacity, and by selling part of their project to other investors, at a high price. The pre-development farm-out strategy may come under pressure as some of the previous buyers now take part themselves in the auctions. Other investors, like pension funds, are still relevant buyers, after the projects have been de-risked by competed

[50] https://www.gov.uk/government/publications/offshore-wind-sector-deal/offshore-wind-sector-deal
[51] https://finans.dk/erhverv/ECE13357198/pensionskasser-i-historisk-kursskifte-nu-er-der-for-faa-penge-i-havmoeller/
[52] This is a reduction from previous target of 6-10%; https://www.equinor.com/en/what-we-do/calendar/capital-markets-day-2021.html.htmlpayback

development and production testing. However, competition has increased, higher interest rates deter investors, and the remaining immature markets may in some instances impose political risk.

Farming out of equity has also been the strategy in our case, Dogger Bank. ENI was to take 20% stake in first two phases of world's largest offshore wind farm in February 2021. Combined value of equity consideration is GBP 405 million or GBP 202.5 million to both SSE Renewables and Equinor for each 10% stake.[53] This means that ENI covers 20% of Capex in the first two phases. We find that this increases the nominal IRR of total capital for SSE and Equinor from 5.6% to 6.2%. An analogous 20% farm-out for phase C of the project in November 2021 of GBP 70 million[54], increased IRR to 6.4%.

Newspapers have commented that this means that the project and offshore wind in general has become more profitable. This is not the case. ENI has hardly better knowledge of the project than the developer and the operating company. What this means is that SSE and Equinor have increased their expected return because ENI have been willing to take on the project with a lower rate on return requirement, as low as 2.7 and 2.9% nominal IRR on the total capital for the two farm-outs, to learn the business and to move against their target of offshore wind production of 25 GW by 2035.The transaction is merely a redistribution of profit among private companies, a zero-sum game. The socio-economic value of the project has not changed. The expected NPV of the project is the same, irrespective of equity transaction.

The question is whether the strategy of obtaining a return above project return in offshore wind by farming out is sustainable. Being an earlier mover may give a competitive edge, in particular for the largest and most complex windfarms. However, the competition over concessions is hard and is likely to become even fiercer, e.g., by new oil companies like BP, ENI and Shell entering the game. We will now see competition between oil majors, utilities, institutional investors, and regional developers. The challenge is that projects are awarded in competitive auctions based on commoditized technology sourced from third-party. Thus, it is difficult to see how players can use other parameters than price or risk to win. This is commented upon in the section "Risk and risk management" in the 2020 Ørsted report: "As the offshore market continues to grow and mature, an increasing number of players have entered the market of renewable energy generation. This has

[53] https://doggerbank.com/press-releases/dogger-bank-wind-farm-announces-eni-as-new-partner-for-phases-a-and-b/
https://www.equinor.com/en/news/20210226-dogger-bank-eni.html
[54] https://www.equinor.com/en/news/202111-dogger-bank-c.html

put pressure on prices in auctions and tenders in excess of what can be explained by the LCoE development."

In the analysis we have not accounted for development cost for Dogger Bank. According to IEA (2018), windfarm developers in the UK are liable for all development costs and responsible for completing all surveys required to satisfy consenting conditions. This liability is a prerequisite to being granted a license and being eligible to apply for a CfD. The development and consenting process can take up to 5 years, with costs of tens of millions of pounds, according to IEA. These costs are analogous to exploration cost in the petroleum industry. To find the full life cycle cost of a petroleum field, the expected monetary value (EMV) is calculated. When calculating the EMV, exploration cost is set as capex and the expected value of the development project, weighted with the probability of a profitable discovery, is set as income. Similar calculations could be done with an offshore windfarm project. To account for the exploration cost, e.g., four exploration wells to make a commercial discovery, oil companies typically make an addition to the CAPM when calculating their required discount rate for development projects.

Front-end investment and long lead times have become highly relevant in the fourth UK wind licensing round. The round contains a new feature in which the potential developers first bid for acreage (project leases for 60 years), and thereafter bid for CfD-prices. In a press release The Crown Estate announces winners in the auction for acreage, project capacity, the location of the acreages and the option fee deposit paid.[55] Oil companies won contracts in a field previously dominated by utilities. The successful bidders have committed to GBP 879 million in option fee deposits.[56] For instance, a consortium of EnBW and BP have committed GBP 231 million for 1.5 GW capacity North East of Anglesey. The seabed cost per MW is more than ten times higher than auctions at the East coast of the USA in 2016-2018; yet an indication of enhanced competitive pressure. The Crown Estate estimates a lead time of 10 years on this type of project; development and consenting process 5 years[57], procurement and CfD process 2 years, and 3 years for construction. [58] The process of obtaining consents and CfDs involves risk, so outcomes in an EMV-analysis will have to be weighted

[55] https://www.thecrownestate.co.uk/en-gb/media-and-insights/news/2021-offshore-wind-leasing-round-4-signals-major-vote-of-confidence-in-the-uk-s-green-economy/ Downloaded 11.02.2021 13:50

[56] Round 4 projects together represent just under 8 GW of potential new offshore wind.
[57] The first consenting process is environmental assessment called Habitats Regulations Assessment (HRA) – by no means a formality, as recent delays to consenting projects in the North Sea have shown. https://www.upstreamonline.com/energy-transition/oil-majors-bp-and-total-win-in-giant-uk-offshore-wind-lease-round/2-1-958870 Downloaded 11.02.2021 14:22
[58] https://www.thecrownestate.co.uk/en-gb/what-we-do/on-the-seabed/offshore-wind-leasing-round-4/ Downloaded 11.02.2021 13:56

by success probabilities and a risk-adjusted rate of return requirement need to be applied. This new licensing system can be expected to substantially reduce discounted values for the developers unless the bidding process for CfDs become less aggressive.

BP led the bidding with an offer about 80% higher than the average of its competitors.[59] BP's bet on a very high transition speed from oil to renewables has caused the stock price to fall much relative to other oil companies, e.g., with reference to this kind of bidding as well as hasty sales of petroleum reserves.[60] What looks like winner's curse must be interpreted as an oil company eagerly reaching for its new and very ambitious windfarm capacity and production targets, where the strategic value and not the project economics was the primary objective. Still, BP says it expects returns of about 8% to 10% with the wind farm integrated into its trading unit. Luke Parker, Vice President of Corporate Research at Wood Mackenzie says to Bloomberg Green that the assets will carry the cost, but to reach target return, which is lower than for oil and gas projects, everything needs to go right, and it's unproven. Among the means to improve profitability, he mentions farm-downs, power trading and technology advances. Equinor demands nominal returns of 10% on oil and gas projects when the oil price averages just USD 30 per barrel (breakeven price) — much lower than the USD 65 per barrel average in the company's current projections — while future wind energy projects are expected to generate returns of 5% to 6%.[61] Demanding a breakeven price of USD 30 per barrel while expecting 65, is a representative capital rationing criterion for major oil companies at the start of 2021.[62] It implies a rate of return requirement of 20-30%, which is in stark contrast to rate of return requirements by the same companies when bidding for and developing windfarms.

After the change in the UK licensing system, which has become analogous to the US system, the cash flow structure of windfarm projects resembles that of petroleum projects. You have initial investment (exploration cost or option fee deposit), there is a lead time of ten years, a high initial investment, and a long operation period followed by decommissioning cost. Risk is lower for windfarm investment due to CfDs but the payback-time is three times as long and the dividend capacity is much smaller. Windfarms have lower expected rentability and lower risk than oil

---

[59] https://www.bloomberg.com/news/articles/2021-02-08/big-oil-takes-over-next-generation-of-u-k-offshore-wind?sref=5dj0X2VO&s=09

[60] https://www.reuters.com/business/sustainable-business/bp-gambles-big-fast-transition-oil-renewables-2021-09-20/?s=09

[61] https://www.upstreamonline.com/energy-transition/equinor-to-increase-renewables-investment-despite-rising-oil-prices/2-1-960755

[62] The average unit cost for discoveries on the Norwegian continental shelf in the period from 2010-2019 is USD 21 per barrel, while the average oil price during the same period was nearly USD 80 per barrel; https://www.npd.no/en/facts/news/general-news/2021/the-shelf-2020-high-activity-and-significant-investments/

projects. A relevant question is whether they are subject to the same decision criteria. Our impression is that windfarm projects are less robust. A proper application of an EMV decision analysis would probably not have been rewarded with success in the fourth UK offshore wind licensing round.

The development in the electricity market is to a large extent determined by political decisions, not market considerations. There are signs of a competition at a national level in developing as much offshore wind as possible. We have new entrants by Poland, seeking security of supply, and Norway, seeking to develop a competitive supplier industry and electricity export. The UK has very aggressive growth plans for offshore wind, a 1000% increase by 2050. Denmark has very aggressive offshore wind export plans with an artificial island as a 10GW wind energy hub.[63] The expansion plans for UK, Denmark and Norway are in the same geographical area. If considerable parts of these supply-driven plans take place, combined with the change from a situation with few developers and no auctions to a system with two auctions and with many aggressive bidders with deep pockets, it is hard to see how this can be reconciled with profitability for offshore windfarm developers.

References

4C Offshore. 4C Offshore – Offshore Wind Farms. Available at: www.4coffshore.com/windfarms.

Aguirre, M. and G. Ibikunle (2014), "Determinants of renewable energy growth", Energy Policy 69, 347-384.

Aldersey-Williams, J., Broadbent I.D., and P.A. Strachan (2019), "Better estimates of LCOE from audited accounts – A new methodology with examples from United Kingdom offshore wind and CCGT", Energy Policy 128, 25-35.

Aldersey-Williams, J., Broadbent I.D., and P.A. Strachan (2021), "Addressing recent misreporting of findings from "Better estimates of LCOE from audited accounts – A new methodology with examples from United Kingdom offshore wind and CCGT", Energy Policy 153, 112240.

Aldersey-Williams, J., Rubert, T., 2019. Levelised cost of energy – a theoretical justification and critical assessment. Energy Policy 2124, 169–179 (January 2019).

BEIS (2020), Department for Busines, Energy & Industrial Strategy, *Electricity generation costs 2020*; https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/911817/electricity-generation-cost-report-2020.pdf

[63] https://www.dw.com/en/denmark-to-construct-artificial-island-as-a-wind-energy-hub/a-56458179

Berg, T.L., Apostolou, D. and P. Enevoldsen (2021), “Analysis of the wind energy market in Denmark and future interactions with an emerging hydrogen market”, *International Journal of Hydrogen Energy* 46, 146-156.

Blomgren, A. (2021), “Lønnsom eksportvirksomhet med komplekse, kontinuerlig høye innkjøp med aktivt innovasjonssamarbeid og høyt nasjonalt innhold. Seks karakteristika ved norskbasert petroleumsvirksomhet som kan forklare virksomhetens sterke spillovereffekter på norsk økonomi». Report from the R&D-project at Norce/UiS: «Learning processes from Norwegian based petroleum activity», funded by the Ministry of Petroleum and Energy.

BP (2019), BP Annual Report and Form 20-F 2019; https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/investors/bp-annual-report-and-form-20f-2019.pdf

Dahl, R.E., Lorentzen, S., Oglend, A. and P. Osmundsen (2017), “Pro-cyclical petroleum investments and cost overruns in Norway”, Energy Policy, vol. 100©, 68-78.

DNV GL (2019), “Future technology improvements. Potential to improve Load Factor of offshore wind farms in the UK to 2035”; https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/839515/L2C156060-UKBR-R-05-D_-_potential_to_improve_Load_Factors_of_UK_offshore_wind_to_2035.pdf

EEA (2009), Europe’s Onshore and Offshore Wind Energy Potential, an Assessment of Environmental and Economic Constraints. Technical report, No 6/2009. ISSN: 1725-2237. European Environment Agency, EEA

Elderer, N., 2015. Evaluating capital and operating cost efficiency of offshore wind farms: a DEA approach. Renew. Sustain. Energy Rev. 42, 1034–1046 (February 2015).

Flyvbjerg, B., Bruzelius, N., and W. Rothengatter (2003), *Megaprojects and Risk: An Anatomy of Ambition*. Cambridge University Press, Cambridge, United Kingdom.

Hagos, D.A. and E.O. Ahlgren (2020), “Exploring cost-effective transitions to fossil independent transportation in the future energy system of Denmark”, Applied Energy, 261:114389.

Hiorth, A. and P. Osmundsen (2020), «Petroleum taxation. The effect on recovery rates», Energy Economics 87, 1-13.

HM Treasury (2020), “Net zero review: interim report”, December, 2020.

Hughes, G., Aris, C., Constable, J., 2017. Offshore wind strike prices – behind the headlines. GWPF Brief. 26.

IEA (2018), *IEA Wind TCP Task 26 – Offshore Wind International Comparative,* by Noonan, M., T. Stehly, D. Mora, L. Kitzing, G. Smart, V. Berkhout, Y. Kikuchi. International Energy Agency Wind Technology Collaboration Programme.

Jaraite, J. and A. Kazukauskas (2013), “The profitability of electricity generating firms and policies promoting renewable energy”, Energy Economics 40, 858-865.

Ketterer, J.C. (2014), “The impact of wind power generation on the electricity price in Germany”, Energy Economics 44, 270-280.

Kesicki, F. and N. Strachan (2011), “Marginal abatement (MAC) curves: confronting theory and practice”, Environmental Science & Policy 14, 1195-1204.

Koch, C. (2012), “Contested overruns and performance of offshore wind power plants”, Construction Management Economics 30 (8), 609-622.

Krohn, S., Morthorst, P.E., Awerbuch, S., 2009. The Economics of Wind Energy: A Report by the European Wind Energy Association. European Wind Energy Association EWEA, Brussels.

Lorentzen, S., Oglend, A. and P. Osmundsen (2017), “Cost overruns on the Norwegian continental shelf: the element of surprise”, Energy, 133, 15 August 2017, 1094-1107.

Merz, K.O (2016), “Dogger Bank reference wind power plant: layout, electrical design, and wind turbine specification”, Sintef Energy Research, January 21, 2016.

Modigliani, F.; Miller, M. (1958). "The Cost of Capital, Corporation Finance and the Theory of Investment". American Economic Review. 48 (3): 261–297.

Morthorst, P.E. and L. Kitzing (2016), “Economics of building and operating offshore wind farms”, in Ng, C. and L. Ran (2016), Offshore Wind Farms Technologies, Design and Operation, Elsevier.

Neill, S. P., & Hashemi, M. R. (2018), *Fundamentals of ocean renewable energy: generating electricity from the sea,* Academic Press.

Osmundsen, P., and M. Emhjellen-Stendal (2022), “No more need for CfDs or feed-in tariffs”, mimeo, University of Stavanger.

Osmundsen, P., Emhjellen-Stendal, M. and K. Løvås, «Investment allocation with capital constraints. Comparison of fiscal regimes» (2022), 43, 1, 263-284.

Osmundsen, P., Asche, F., B. Misund, and K. Mohn (2006), “Valuation of International Oil Companies”, Energy Journal, 27, 3, 49-64.

Osmundsen, P., Mohn, K., Asche, F., and B. Misund (2007), “Is the Oil Supply Choked by Financial Markets?”, Energy Policy 35, 1, 467-474.

Oswald, J.R. and H. Ashraf-Ball (2008), “Will British weather provide reliable electricity?”, Energy Policy 36, 3212-25.

Partridge, I., 2018. Cost comparisons for wind and thermal power generation. Energy Policy 112, 272–279.

Sovacool, B.L., Enevoldsen, P., Koch, C. and R.J. Barthelmie (2017), “Cost performance and risk in construction of offshore and onshore wind farms”, Wind Energy, 20, 891-908.