Oil Company Investment in Offshore Windfarms: A Business Case

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ABSTRACT

European petroleum majors have moved into offshore windfarm projects, with large investments and ambitious capacity and production targets. In aggressive bidding for Contracts for Difference in the UK, where oil companies have played a key part, we have seen the inflation-adjusted strike price fall 65% from 2015 to 2019. Researchers question whether LCOE will fall to the same extent and would like to see more research on the economic return of the companies making offshore wind investment. We address this by a transparent project economics analysis of the UK bottom-fixed Dogger Bank project. It is the largest offshore windfarm project in the world under development and the UK is the country with highest offshore wind capacity. The project is owned by Equinor, SSE Renewables and ENI. Our analysis shows that the project is expected to be unprofitable. Several of the input variables, however, are subject to considerable estimation uncertainty. We also present a low case and a high case scenario. Decomposition of the high case reveals factors that can contribute to a profitable wind power industry. We discuss financial issues facing oil company investment portfolios combining low return/low risk renewables and high return/high risk petroleum. Offshore windfarms are organised as special purpose vehicle (SPV) companies. We analyse the economic interactions between the SPVs and the oil companies, and address accounting and financial issues.

Keywords: Offshore windfarms, Project profitability, Contracts for Difference, Oil company transition

https://doi.org/10.5547/01956574.44.6.posm

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. For valuation of oil companies, it is essential to determine whether 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

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The Energy Journal, Vol. 45, No. 2.

is taking place in the major European oil companies.[1] 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.[2] BP has an even more offensive strategy; a cut in hydrocarbon generation of 40% by 2030.[3] This means that the extreme 2020 capital rationing of petroleum investment of international oil companies, 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 be maintained. The rise in prices of oil and natural gas after the relaxation of COVID-19 restrictions has reduced the need for capital rationing.

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 windfarms and expected economies of scale, investment per MW in offshore windfarms has 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 windfarms, 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.[4] 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 57.5/MWh, and current modern windfarms 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, but that we have seen reductions in the rate of return requirement also in the following years. The 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. The concern for dramatic revenue reductions and lack of profitability in windfarm development is shared by key analyst companies like Wood Mackenzie, that make clear that this is not a specific problem relating to the UK but a global issue.[5]

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], i.e., a

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

2. 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).

3. https://www.cnbc.com/2020/08/05/bp-ceo-says-dividend-cut-deeply-rooted-in-strategy.html.

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

5. https://www.offshorewind.biz/2021/12/23/offshore-wind-revenue-mwh-to-drop-66-per-cent-between-2014-and-2025-woodmac/.

6. «Breakdown Information on CfD Auctions», Department of Energy and Climate Change (DECC), 2015.

7. «Contracts for Difference Allocation Round 3 results», BEIS, 2019.

reduction of 65% over four years. 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 used by 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 company profitability of the Dogger Bank offshore windfarm project is a contribution to fill some of these gaps. Evaluating profitability of windfarms 9involves complex issues of technology, markets, accounting and finance. We find that this is best achieved by a detailed case analysis. 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.[9]

With the new role of major oil companies in offshore windfarm developments, 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. Our main focus is project economics at the time of project sanctioning, using standard oil company valuation methods. Since selling out part of the project to other investors is part of the business strategy of windfarm developers, we also calculate project economics after so-called farm-outs.

As far as we have been able to determine, project analyses of windfarm investment projects are only available to subscribers of investment bank reports. Unlike such reports, our project analysis is transparent. We explain pedagogically how an investment analysis is set up and the data sources we use, and we perform scenario analysis. We use input variables that we find to be representative for developers sanctioning windfarm projects in that period and we evaluate the consequences of simplifying assumptions often made in evaluating windfarm investments. To our knowledge, this has not been done previously in the literature.

2. DATA

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 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, capturing data from press

8. https://www.gov.uk/government/publications/contracts-for-difference/contract-for-difference.
9. https://www.equinor.com/en/news/2019-09-19-doggerbank.html, downloaded 2701
21, 13:30.

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.

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.[10] 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) andthe 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, while noting its limitations when analysing future projects (Aldersey-Williams et al., 2021). 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 scenario analysis.

Dogger Bank started investment in 2020 and is scheduled to have first production in 2023. Thus, we need to rely on available cost estimates. However, we compare it with existing industry Capex norms and 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).

We evaluate the consequences of simplifying assumptions that are often are made by investment banks in evaluating windfarm investments. Examples of simplifications are using a stable operation cost even if it is actually 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 CfD-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.

We now turn to cost and revenue of our windfarm case. The Dogger Bank windfarm is located 130—190 km from the Northeast coast of England.[11] The windfarm was according to the

10. With this organisation, the risk of the windfarm is insulated from the parent company, and sales of assets are easier.
11. https://doggerbank.com/ Downloaded 180221, 11:13.

homepage estimated to be operational for 25 years.[12] 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%).

In working with the case, we have had much benefit from discussions with academic colleagues—in particular researchers at Aarhus University and the Norwegian School of Economics—and from input and feedback from an industry reference group for this research project, consisting of experts from oil companies, wind turbine industry, service industry, utilities and finance.

3. 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 known, so there is information on the duration of the investment period, but not how investment evolves over time. Operation expenditure (Opex) is typically not available. Assumptions can be made based on accounting data for other windfarms and available research.

Opex is usually estimated to 25% of overall cost, in net present value terms.[13] Whereas Capex accrues in the first years of a project, Opex accrues over the entire production period. 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 an assumption needs to be made about Opex development.

Dogger Bank Wind Farm consists of three projects: Dogger Bank A (DBA), Dogger Bank B (DBB) and Dogger Bank C (DBC). The expected 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. Sovacool et al. (2017) find a mean cost overrun of 9.6% for offshore wind farms. Dogger Bank is a megaproject, by all standards. In other industries, megaprojects face larger overruns, see Flyvbjerg et al. (2003) and Dahl et al (2017). 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. Scarce capacity and bottlenecks in the supply chain, that currently characterises the offshore windfarm industry, is a well-documented cause of cost overruns (Lorentzen et al., 2017) and have been an issue in offshore windfarm cost overruns. The turbine producer Vestas reports that prices of steel, copper and blade material have more than doubled last year.[14] According to Equinor, this risk is shared among the developers and the suppliers.[15] A factor that calls for cost cuts is that we have used the original Capex-estimate based on 12 GW turbines in our base estimate. The project is using larger turbines, 13 MW and possibly 14 MW in phase C. This may give cost reductions in terms of fewer foundations and less cabling.

12. Aldersey-Williams et el. (2019) write that windfarms usually have a 20-25 year operating life, and they use 25 years in their analyses.

13. This corresponds with the finding of 90% of nominal Capex in Ng and Ran (2016), p. 6.

14. https://energiwatch.dk/Energinyt/Renewables/article13563685.ece.

15. https://www.upstreamonline.com/exclusive/worlds-largest-offshore-wind-farm-unprofitable-for-equinor-say-government-funded-researchers/2-1-1098012.

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, we find that it has minimal impact on the present value of the investment cost. By our assumption of 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 in net present value terms this will mostly cancel each other out.

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 potential 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 nominal decommissioning cost to 25% of Capex, based on industry sources. This cost element is often left out in investment bank analyses. It is also ignored in BEIS (2020), with the assumption that decommissioning costs is equal to the scrap value of the plant. According to our industry panel, this assumption is not realistic. Our decommissioning cost estimate is higher than BEIS (2018). There is almost no experience in decommissioning of offshore wind turbines. To estimate decommissioning cost 25 years ahead is very challenging; there may be learning effects in the industry that reduce cost over time and new environmental standards may emerge that increase cost. The petroleum industry has seen some large cost overruns in decommissioning. At any rate, cost that occur 25 years into the future has limited impact on project economics calculations. The NPV of our estimated decommissioning cost is GBP 212 million, or 2.63% of the NPV of Capex, and it plays a minor part in the economics of this huge project. A question raised about decommissioning is whether it could be postponed by re-using the substructures by installing new turbines (repowering). According to industry experts this is currently not a viable strategy since the substructures are not likely to be certified for reuse and since making use of innovations in turbines probably would necessitate another type of substructure. However, it could lead to reduced decommissioning cost in future developments.

Tax depreciation (capital allowances) is given at 18% using the declining balance method. The tax rate is reduced to 17%, effective from 2020. We have used this rate from the time of project sanctioning in our project calculation. It is later announced that the UK corporate tax rate is to be increased to 19% by April 2022 and 25% by April 2023.[16] This will reduce NPV of the project. In addition to corporate income tax, according to IEA (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 more details on cost estimation, see Osmundsen et al. (2021).

16. https://www.gov.uk/government/publications/corporation-tax-charge-and-rates-from-1-april-2022-and-small-profits-rate-and-marginal-relief-from-1-april-2023/corporation-tax-charge-and-rates-from-1-april-2022-and-small-profits-rate-and-marginal-relief-from-1-april-2023.

4. REVENUE

Production is 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.[17] The annual expected quantity of electricity produced is in principle 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* · 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. We set the capacity factor at 55%, a number that we believe was a representative estimation of developers sanctioning projects at that time. In our project profitability estimation, we keep the capacity factor constant over time. Our industry reference group finds this to be an optimistic assumption and fear that project economics and duration may be reduced by production decline. Analysing UK onshore windfarms, Hughes (2012) find strongly declining capacity factors over time, and an even higher rate of decline in performance for Danish offshore windfarms. Lu et al. (2022) find a non-linear relationship between capacity factor and age for UK offshore windfarms; an inverted U-chape between capacity factor and age, whereby production declines more than 5% over the lifetime.

Equation (1) provides a summary of the income calculation.

$$Income_t = Capacity \cdot 1000 \cdot \left(24\, hours \cdot 365\, days\right) \cdot \begin{matrix} Capacity \\ factor \end{matrix} \cdot price_t \tag{1}$$

The capacity factor is the fraction of the time the turbines reach 100% of the capacity.[18] Usually, the metric also accounts for downtime. IEA (2018) reports that the average capacity factor for UK windfarms being commissioned in 2017-2018 is 42.3%. 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 reached the highest capacity factor we have found in the literature—45%. Being farther ashore than other windfarms implies more consistent wind, and using considerably larger turbines than previously, call for a higher capacity factor for Dogger Bank. Still, a leap from 45% to 55% (an increase of 22%) is an ambitious target in an industry that so far has seen more gradual improvements. For 2025, BEIS (2020) project a turbine size of 12MW and a load factor (net of availability) of 51%, increasing to 15MW and 57% in 2030. DNV GL (2019) estimate a generic capacity factor for next generation wind turbine generators (10-12MW) in the mid-2020s to 50.3%. For more discussion on capacity rate estimation, see Osmundsen et al. (2021).

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 mechanical assumption. According to industry experts there is reason to be concerned of falling production over time. We

17. 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.

18. A more precise definition is provided by Neill and Hashemi (2018): 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 ideal state for the same time period.

have not accounted for this. Neither have we accounted for the prediction in the latest IPCC report that average wind speeds over Europe will reduce by 8%-10% as a result of climate change.[19]

The official website for Dogger Bank wind farm reported an expected lifespan of 25 years.[20] BEIS (2020) assumes an operating period of 30 years for projects sanctioned in 2025. The operation period is divided into two segments: the first 15 years when the wind farm operates with a known, fixed electricity price and the last 10 years when it is subjected to market prices, and where price assumptions have to be made. The fixed price is in 2020-terms GBP/MWh 45.83 for DBA and GBP/MWh 48.09 for DBB and DBC.[21] The market price is estimated in the following manner. We start by calculating 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.

In 2018 Denmark had 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[22], 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. In a study of the Danish electricity market, however, Rintamäki et al. (2017) find that wind power output decreases daily price volatility, because wind speeds here are roughly evenly distributed throughout the day and Denmark has high transmission capacity to the Nordic countries with large hydropower reservoirs.

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. In the literature this is denoted capture price. Production from power production that can be regulated and can be turned on and off in response to the price level, has higher value than for offshore wind that cannot be regulated (Joskow, 2011). 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).

19. https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter_12.pdf.

20. https://web.archive.org/web/20210104104342/https://doggerbank.com/. When announcing announced contracts confirming the 13MW Haliade-X turbine, Equinor referred to a lifetime of at least 25 years; https://www.equinor.com/en/news/20200922-dogger-bank.html. The producer GE does not quote a lifetime for this turbine; https://www.ge.com/renewableenergy/wind-energy/offshore-wind/haliade-x-offshore-turbine. The warranty period is 5 years, contingent on a service agreement.

21. https://www.gov.uk/government/publications/contracts-for-difference/contract-for-difference.

22. The same result is found in research on U.S. data, see Ontario, Rivard and Yatchew (2016) and Schmalensee (2016).

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 have so far been carried out; the fourth round of the CfD-scheme, set to open late in 2021, aims to support up to 12 GW.[23] At the end of 2019 the capacity was 8.6 GW. A key question is to what extent the expected dramatic increase in windpower 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 multiply our price estimate—a combination of current UK and Danish prices—by an adjustment factor less than one, accounting for the value difference between intermittent offshore windpower and the general electricity market.[24] We set the factor equal to 0.9, which is an optimistic estimate according to our industry and academic reference group. 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. Table 1 summarizes the effects of our assumptions on before tax cashflows.

5. RATE OF RETURN REQUIREMENT

For our case 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. It is our view that the return requirement should be different for the two periods.

We evaluate the project according to common industry profitability criteria. When evaluating the required return on the project we apply a standard capital asset pricing model approach. We assume the oil 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).[25] Using a market risk premium of 6.0% (data from Damodaran's web site, January 5th, 2021), and assuming a bond beta of about 0.3, we get an expected return 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,

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

24. Our adjustment factor is related to the term "value factor" used in the literature, defined as the market price for wind power divided by the base price, see e.g., Blume-Werry et al. (2021). We use market price for electricity instead of base price. Value factors for offshore wind are generally falling with the penetration of offshore wind power. Blume-Werry et al. make model prediction for value factors in European counties, showing substantial reduction. For Germany, a country with high penetration of wind power, the modelled value factor for offshore wind is reduced from around 90% in 2020 to around 73% in 2050.

25. 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 the period chosen.

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

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			

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, 2021). 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). [26]

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, which means an overvaluation of the project relative to traditional decision methods.

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.[27] The owners of the Dudgeon wind farm, Equinor, Masdar and China Resources Group, signed a hybrid refinancing of GBP 1.4 billion, with A- (EXP) rating.[28] The loan rate is not disclosed. 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 in the range 1 to 1.5 percentage points above Libor.[29] 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. To allocate rationed capital to the best projects, oil companies normally use standardised financial assumptions set on the corporate and not the project level.

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 not according to finance research 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 thus 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 (to be explained below), 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 (Osmundsen et al., 2021) are in accordance with the Miller-Modigliani theorem. A debt rate of 70% or above 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.

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

27. https://www.equinor.com/en/news/20201126-doggerbank-financial.html. https://www.equinor.com/en/news/20211201-financial-close-dogger-bank.html.

28. https://www.equinor.com/en/news/2018-12-12-dudgeon.html.

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

6. PROJECT ECONOMICS

We use 25 years as expected production period. 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. Nominal decommissioning cost is set to 25% of Capex (NPV of decommissioning cost is 2.63% of NPV 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 49.9 GBP 2020/MWh after 2038, the project economics is presented in Table 2.

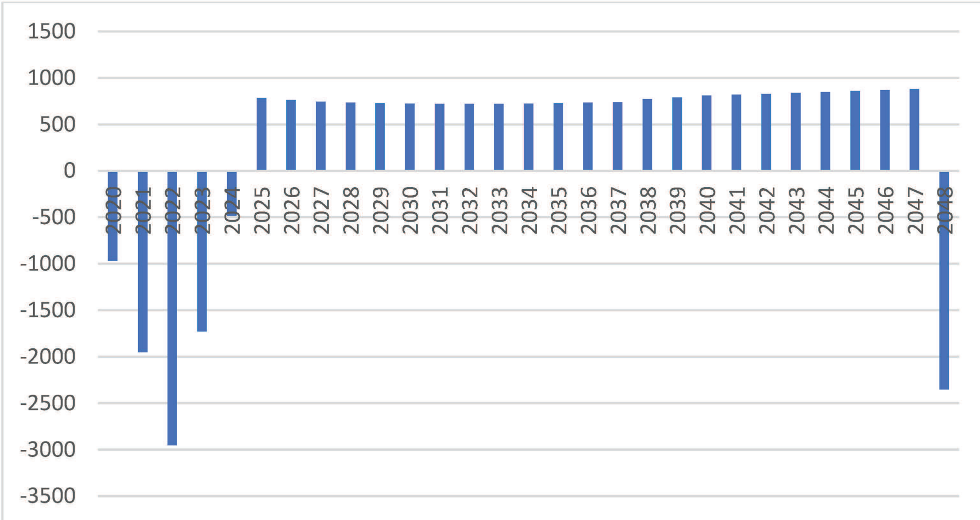
Table 2: Expected project economics of Dogger Bank wind farm.

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 shows the results of project economics with the before tax and after tax cashflows. It also contains the debt cashflow and the discounted cashflow with the fixed price discount rate (5,9%) and the market exposed discount rate (8.5%). The cashflow is displayed in Figure 1.

Figure 1: Nominal cash flow after tax for the Dogger Bank project, at the time of project sanctioning.



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 table 2 we also show payback on the total capital stream and the equity capital stream. As the results demonstrate, the expected NPV is a negative GBP 1789 million 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, as we recommend, gives a NPV of a negative GBP 907 million. The internal rate of return of the 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. Decommissioning cost has minor effect on profitability. If we reduce our estimated decommissioning cost by as much as 90%, nominal IRR on total capital increases only to 6.1% and NPV still becomes a negative GBP 774 million.

We calculate the return to the initial owners after the sale to ENI. 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[30], would imply an estimated increase in the IRR of total cash flow to 6.2%, nominal for the initial owners. For ENI this acquisition would yield an estimated IRR of total capital invested of only 2.7% nominal. After the second farm-down to ENI in November 2021, a 20% interest in phase C for GBP 140 million, expected overall IRR for SSE and Equinor increases to 6.4% nominal, and ENI is expected to get 2.9% nominal IRR in the second transaction.

The payment in the second farm-out was 30% lower per MW. This is consistent with indications that the farm-out strategy, i.e., the strategy of making a gain when farming out parts of projects, 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 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."

30. https://www.equinor.com/en/news/20210226-dogger-bank-eni.html.

Equinor ascribes the reduction in farm-out payment to the fact that UK corporate income taxes are announced to increase and that the third phase of the project is more costly to develop due to longer distance from shore and larger water depth.[31]

In the project profitability assessment, we have used cost and revenue assumptions that were representative for oil companies at the time of project sanctioning (2020). In research and industry there is a fairly large divergence on these assumptions. To convey a range of possible outcomes, we have undertaken a scenario analysis. In addition to the investment analysis already presented—the base case—we present a low case and a high case. In the scenarios we change the input variables that have the largest impact on profitability: commercial electricity price from 2038, capex, capacity factor, and operation time.[32] This is determined by a sensitivity analysis of the base case, see Osmundsen et al. (2021).

We use an interval of +/- 5 years for project duration relative to the assumption at project sanctioning of 25 years—20 years duration for the low case and 30 years duration for the high case—i.e., a change of 20%. For Capex we also use +/- 20%. Since our estimates for Opex and decommissioning cost are linked to Capex, these are changed accordingly. In the upside case, the NVP of decommissioning cost is further reduced by delayed decommissioning. NPV of decommissioning cost is now 1.83% of the NPV of Capex. The interval used for capacity factor is +/- 5%. For market price we calculate the variance of 10 years of quarterly data and use +2 standard deviations for the high case (76.33 GBP 2020/MWh) and –1 standard deviation for the low case (36.49 GBP 2020/MWh).[33] Some of the high case assumptions, e.g., Capex –20%, are probably not realistic for the Dogger Bank case. Our scenario analysis can be seen as a way of making the analysis relevant also for projects in other parts in the world and to investments set to happen later in time. For instance, cost reductions can be due to learning effects, often defined as the cost reduction achieved for each doubling of cumulative output (Williams et al., 2017). Cost may come down between each subsequent generation of wind farms by changes in turbine size, size-agnostic innovations, and increased supply chain efficiencies and industry learning (NREL, 2022). Decommissioning cost may come down as a consequence of repowering (Jadali et al., 2021; Cook and Lawall, 2020; Fitzgerald and Giberson, 2021).

The high case has an IRR of 11.2%, up from 5.6% in the base case, and NPV of GBP 3020 million GBP. The low case has an IRR of –2.4% and NPV of –4028. Thus, the scenario analysis generates a wide span for project economics and highlights what parameters need to improve to achieve profitability. See the appendix for details of project economics of the upside and downside scenarios.

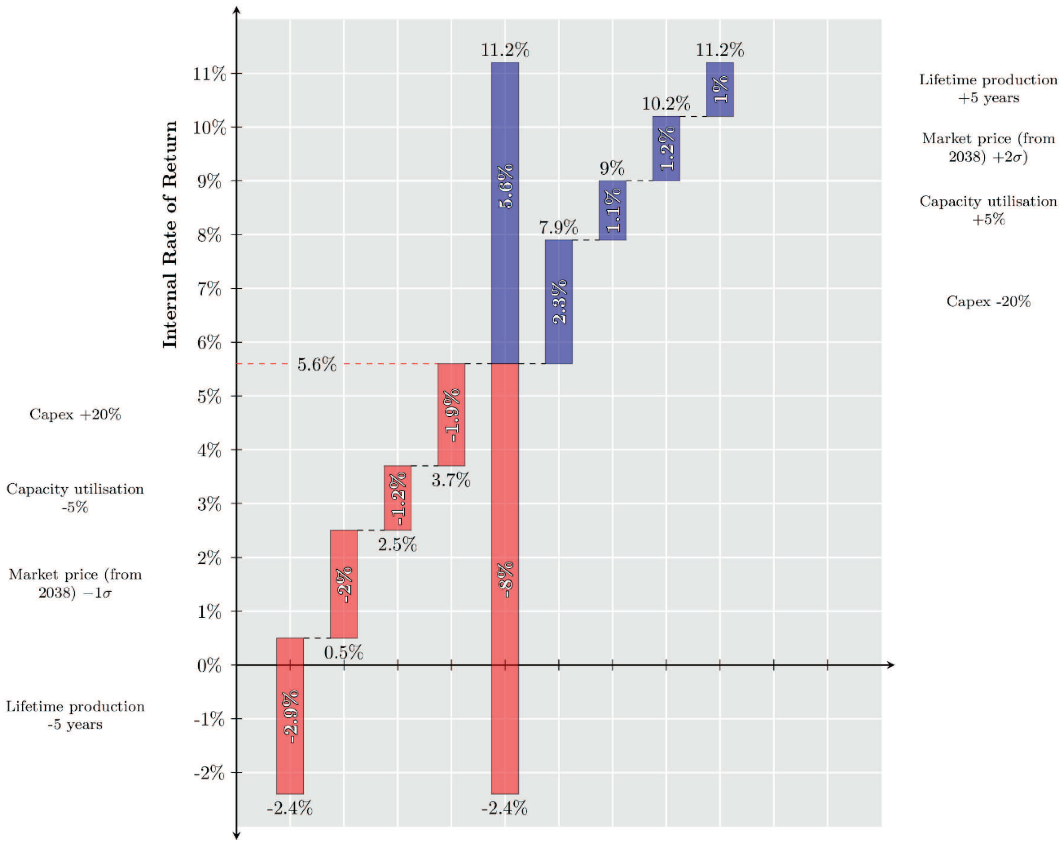
Figure 2 illustrates how the upside and downside scenarios deviate from the base case IRR of 5.6%. In the downside scenario IRR is reduced by 8%, and it is increased by 5.6% in the upside scenario. The figure also illustrates how the increase or decrease in IRR is explained by changes in capex, capacity utilitisation, market price, and lifetime of production. While premature abandonment plays a key role in the downside scenario, reducing capex is essential in an upside scenario. The scenarios are based on current fiscal terms and CfD-prices. For developers to reach profitability near the IRR in the upside scenario, fiscal terms must not deteriorate and competitive

31. https://www.upstreamonline.com/exclusive/worlds-largest-offshore-wind-farm-unprofitable-for-equinor-say-government-funded-researchers/2-1-1098012.

32. One input factor not considered, that may be significant for project economics, is deviation in project execution time. In the current situation, supply chain bottlenecks may generate a delay.

33. We consider –2 standard deviation (23.11 GBP 2020/MWh) to be outside the relevant range.

Figure 2: Illustration of upside and downside scenario. Deviation from base case and decomposition.



pressure in bidding rounds must be reduced, e.g., by consolidation in industry or by imposing more discretionary licensing criteria.

7. ACCOUNTING ISSUES

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 (Osmundsen et al., 2006, 2007).[34] 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.[35] 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

34. 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.

35. 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.

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.[36] 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 CfDs, 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 nominal decommission cost is 25% of Capex, there is an additional off balance decommission obligation for Equinor of GBP 0.9 billion on 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[37]; later updated 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 1.44 GW, i.e., the debt is about GBP 1.7 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 27 billion. Analogously, the off balance decommission commitment would be GBP 10 billion. Recently, Equinor has emphasised that 12–16 GW by 2035 is not a target for the company, but merely an ambition.[38] Executive Vice President for renewables in Equinor, Pål Eitrheim, says the renewable industry is challenging; there is extremely tough competition over far too few projects. Equinor prefers to invest in profitable projects and would not like to deliver 12 GW that does not generate value for the company. The company will not anymore participate in regular auctions, according to the Executive Vice President.

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. This is not currently the case, off balance debt is not listed in the consolidated accounts. Investors, if they are properly informed, can access the accounts of the SPVs, at least this is the case

36. https://www.ifrs.org/projects/work-plan/equity-method/.

37. https://www.equinor.com/en/news/20201102-emissions.html, downloaded 210221, 16:54.

38. https://www.dn.no/energi/equinor/fornybar-energi/olje-og-gass/equinor-vasser-i-penger-men-oker-ikke-fornybar-takten-vi-har-rad-til-a-vare-disiplinerte/2-1-1166421

in the UK. However, this is time consuming work and may prove challenging in emerging offshore wind regions.

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[39], Equinor has to put up an equity of GBP 0.80 billion on this particular project. The Equinor share of the capacity is 1.44 GW, so it took an equity of GBP 0.6 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 9.6 billion. This is a very crude calculation the point is merely that the need for equity is high. It would probably come out of the cash flow from petroleum activity, leaving less room for petroleum investment. The estimate presumes 70% debt. The actual need for equity will be even higher since the developers are 100% equity financed in the development phase.

8. DISCUSSION OF RESULTS

The internal rate of return of the project is 5,6% nominal 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).[40] This figure has come down, Equinor reports payback times of only one and a half years on non-sanctioned projects (not counting exploration cost).[41] 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% by 2030.[42] There are varied reasons why oil companies might wish to invest in offshore wind projects, beyond profitability and return. Having at least a foot in renewable energy may make financing cheaper and easier to access for a petroleum company. It may make recruitment and marketing easier. Companies may also seek to gain experience in a growing market.

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 15 years. The developers then face considerable systematic price risk, similar to petroleum projects, 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

39. https://www.equinor.com/en/news/20210226-dogger-bank-eni.html. https://www.equinor.com/en/news/202111-dogger-bank-c.html.

40. https://www.npd.no/en/facts/news/general-news/2020/profitable-exploration-on-the-norwegian-shelf/.

41. https://www.equinor.com/en/what-we-do/calendar/capital-markets-day-2021.html.html.

42. https://www.cnbc.com/2020/08/05/bp-ceo-says-dividend-cut-deeply-rooted-in-strategy.html.

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. 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.[43]

The Dogger bank project and Energy-trading company Danske Commodities[44] 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.[45] 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.[46] 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 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.

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; 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 allow 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 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. Project economics may also be exposed to time overruns. According to Koch (2012), offshore wind projects had an average time overrun of 45% from 2004 to 2008.

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

43. 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.

44. The Aarhus, Denmark-based firm was acquired in 2018 by Equinor. https://www.equinor.com/en/news/2019-02-01-danske-commodities.html.

45. https://www.upstreamonline.com/energy-transition/energy-trader-signs-first-power-purchase-deal-at-world-s-largest-offshore-wind-farm/2-1-859008.

46. https://doggerbank.com/project-news/power-purchase-agreements-signed-for-dogger-bank-a-and-b/.

gives low return on investment, it may deter future investment. An analogy might be shale oil and gas investments in the US. Huge investments in US shale developments, mainly volume driven, produced little in terms of economic return. On the contrary, consolidated accounts were heavily affected by large impairment charges from the shale activity. This led to a shift in focus, away from volume and to investment return. Shale investments went down and are still not back to the previous level.

Access to capital for offshore windfarm projects has been 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.[47] Facing increasing inflation, the national banks in countries like the UK, Norway and the USA signalled in December 2021 a sequence of increases in their 2022 lending rates to banks.

9. CONCLUSIONS

Project calculation of the scheduled Dogger Bank windfarm proved to be a challenging 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 and 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 find that the most critical input parameters are investment cost, the capacity factor, market price of electricity and duration of production.

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 a project base case NPV of negative GBP 907 million and an IRR of total capital of 5.6% nominal (6.4% nominal for the original owners after farm-downs), considerably lower than for previous windfarms, we conclude that it is a combination. We perform a scenario analysis with a low case related to cost overruns and cannibalisation and a high case with cost reductions and higher value of electricity. The high case illustrates what factors that need to improve to secure profitability in future projects.

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 17 years makes it hard to fund new investment from free cash flow,

47. Even for the low interest period 2009-2019, the US ten-year treasury bond had an average real annual rolling rate of return of 3.1% (data from Morgan Stanley, via Bloomberg).

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.

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] Irrespective of accounting policy selected, reallocation of investments from petroleum to offshore wind implies lower return on capital and weakened dividend capacity.

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.[50] 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 seem to state return targets above the expected return levels for new windfarms. For instance, Equinor states a target of 4–8 % real return on this activity, exclusive of farm-outs. With an inflation rate of 2%, the estimated 3.6 real IRR we find for the Dogger Bank project (exclusive of farm-downs) is below target.[51] The interval is in 2021 reduced from the previous target of 6–10% real return.

Windfarm developers have been able to improve returns significantly by farm-outs. Farming out of equity has also been the strategy in our case, Dogger Bank. ENI has taken a 20% stake via two pre-development transactions in 2021. We find that this increases the nominal IRR of total capital for SSE and Equinor only increase from 5.6% to 6.4%.

The competition over concessions is hard and has become even fiercer, after oil companies like BP, ENI and Shell have entered the game. We 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.

Front-end investment and long lead times have become 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.[52] Oil companies won contracts in a field previously dominated by utilities. The successful bidders have committed to GBP 879 million in option fee deposits.[53] For instance, a consortium of EnBW and BP have committed GBP 231 million for 1.5 GW capacity Northeast 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

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

50. https://finans.dk/erhverv/ECE13357198/pensionskasser-i-historisk-kursskifte-nu-er-der-for-faa-penge-i-havmoeller/.

51. 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.

52. 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.

53. Round 4 projects together represent just under 8 GW of potential new offshore wind.

Crown Estate estimates a lead time of 10 years on this type of project; development and consenting process 5 years[54], procurement and CfD process 2 years, and 3 years for construction.[55] The process of obtaining consents and CfDs involves risk, so outcomes in an EMV-analysis will have to be weighted 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.[56] 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.[57] What looks like winner's curse (Hughes, 2020) could 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%.[58] 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.[59] 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 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.

54. 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

55. https://www.thecrownestate.co.uk/en-gb/what-we-do/on-the-seabed/offshore-wind-leasing-round-4/. Downloaded 11.02.2021 13:56

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

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

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

59. 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/

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.[60] 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 in the short term can be reconciled with profitability for offshore windfarm developers. At the same time, it cannot be reconciled with the EU-countries' ambitious capacity targets for offshore wind. This has led to new perspectives in the discussion over North Sea offshore wind.[61] The industry now openly acknowledges economic difficulties; cost is increasing, large parts of the value chain are losing money and developers complain that it is hard to find profitable projects. A considerable part of this is due to temporary bottlenecks and increasing prices of raw materials, but the industry also points to structural problems related to aggressive bidding. In the longer term, project performance can be improved, e.g., by continued cost reduction and increased electricity prices, as demonstrated by our high value scenario. If competitive pressure remains very high, however, this does not necessarily imply profitability for the companies, it may instead generate increased auction payments. Thus, the industry asks for discretionary auctioning criteria and state aid. Another path that may lead to restoration of profitability is industry consolidation.

Some of the other new business segments targeted by oil companies—like seabed minerals, CCS and hydrogen—are characterised by higher entry barriers and thus higher profit potential. These segments also seem more aligned with the competence and the infrastructure currently held by oil companies. It is our impression that oil company boards and management do not disagree with this strategy analysis, but the other business segments are less mature and thus offshore wind seems like the activity that will generate most renewable capacity and production in the short term.

The Russian attack on Ukraine has led to an 80% reduction in Russian natural gas export to the EU, which has resulted in record average power prices in the short term. This seems like good news for wind parks like Dogger Bank, but this is not straight forward. Higher power prices would eventually be of benefit only some time into the future, since the first 15 years of production the price is already set by the CfD-contract. The short-term effect on project economics probably is negative, as the energy crisis has led to increase in cost and higher interest rates. The long-term effect is unclear. EU seems to be successful over time in replacing Russian pipeline gas by LNG from other sources. This may come at a cost and may contribute to higher average power prices. The effect on the prices captured by offshore wind parks will also depend on the pace of expansion in wind parks, which may increase as an EU policy response to the energy crisis. Finally, if capture prices were to go up, one must also enquire whether the wind power projects get to keep the increased profits. Orsted lists regulatory intervention among its key risks in the 2022 annual report: "With the increasing power prices throughout Europe, the governing bodies have started to implement price caps or windfall taxes to help businesses and consumers with their increasing power bills. This could have an adverse impact on our revenue from power generating activities if implemented without consideration of fixed-price contracts and hedged volumes."

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

61. https://energiwatch.dk/Energinyt/Renewables/article13912843.ece. https://energiwatch.dk/Energinyt/Renewables/article14437709.ece.

ACKNOWLEDGMENTS

The paper is based on Osmundsen et al. (2021), a report on a research program by Norce / the University of Stavanger, funded by the Norwegian Ministry of Petroleum and Energy. The research program addresses industry potential in renewables. Lorentzen and Osmundsen are thankful to the Ministry of Petroleum and Energy for research funding. We very much appreciate useful comments and suggestions from the editor and three anonymous referees. We are also very thankful for constructive comments by 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 Ove Røsok, Teodor Sveen-Nilsen and Hans Wilhelm Vedøy. All analysis and conclusions are solely the responsibility of the authors. We are also thankful to comments at 43rd IAEE International Conference, June 7, 2021, and at the NPF 2021 Annual petroleum economics conference, October 28, 2021.

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APPENDIX

Project economics of upside scenario

Table A1: Expected project economics of Dogger Bank wind farm, upside scenario.

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 2032	Nominal Equity Cap. 100% removal	Payback Year Equity 2029
IRR	11,8 %	16,1 %	11,2 %	11,5 %	4,8 %	(5,9%, 8,5%)*		16,2 %	
Year/NPV	2 793	2032	2032	2032	0	3 020			
2020	-800	67	-776	-776	-842	-776	-776	67	67
2021	-1632	-1055	-1562	-1555	-500	-1 475	-2 338	-1 055	-988
2022	-2497	-1591	-2363	-2352	-761	-2 106	-4 701	-1 591	-2 579
2023	-1442	-826	-1324	-1306	-480	-1 114	-6 024	-826	-3 405
2024	-331	-56	-263	-240	-183	-209	-6 287	-56	-3 462
2025	824	712	814	840	128	611	-5 473	712	-2 750
2026	835	703	800	826	123	567	-4 673	703	-2 047
2027	847	697	790	816	119	529	-3 882	697	-1 349
2028	858	695	784	810	116	495	-3 098	695	-655
2029	870	694	781	808	113	466	-2 317	694	39
2030	882	696	780	807	112	439	-1 536	696	735
2031	894	699	782	809	110	415	-755	699	1 434
2032	906	703	785	812	109	394	30	703	2 136
2033	919	708	789	817	109	374	819	708	2 845
2034	931	715	795	823	108	355	1 614	715	3 559
2035	944	722	801	830	108	338	2 415	722	4 281
2036	956	730	808	838	108	322	3 223	730	5 011
2037	969	738	816	846	108	307	4 040	738	5 750
2038	1243	899	1042	1072	173	238	5 081	899	6 649
2039	1508	1052	1260	1290	238	265	6 341	1 052	7 701
2040	1783	1208	1487	1517	308	289	7 828	1 208	8 909
2041	1812	1218	1509	1538	320	270	9 337	1 218	10 127
2042	1841	1228	1533	1560	333	253	10 869	1 228	11 355
2043	1871	1237	1556	1583	346	236	12 426	1 237	12 592
2044	1901	1245	1581	1606	361	221	14 007	1 245	13 836
2045	1932	1253	1606	1629	376	207	15 612	1 253	15 089
2046	1963	1259	1631	1652	393	194	17 244	1 259	16 348
2047	1994	1265	1657	1676	411	181	18 900	1 265	17 614
2048	2026	1274	1689	1706	432	170	20 590	1 706	19 319
2049	2212	1362	1836	1850	488	170	22 426	1 850	21 169
2050	2248	1364	1866	1876	512	160	24 292	1 876	23 046
2051	2285	1365	1896	1903	538	149	26 188	1 903	24 949
2052	2322	1364	1927	1930	566	140	28 116	1 930	26 879
2053	-1009	-597	-838	-840	-243	-56	27 278	-840	26 039

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

Project economics of downside scenario

Table A2: Expected project economics of Dogger Bank wind farm, downside scenario.

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 2039	Nominal Equity Cap. 100% removal	Payback Year Equity "2042"
IRR	-11,9 %	-12,4 %	-2,4 %	-2,3 %	4,8 %	(5,9%, 8,5%)*		-12,4 %	
Year/NPV	-5 117	-4678	-4678	-4678	0	-4 028			
2020	-1200	-2218	-1163	-1163	1054	-1 163	-1 163	-2 218	-2 218
2021	-2448	-1688	-2343	-2352	-663	-2 212	-3 506	-1 688	-3 906
2022	-3745	-2501	-3545	-3548	-1047	-3 160	-7 051	-2 501	-6 407
2023	-2339	-1466	-2132	-2127	-661	-1 794	-9 183	-1 466	-7 873
2024	-864	-432	-700	-689	-257	-556	-9 882	-432	-8 305
2025	669	598	751	764	166	563	-9 132	598	-7 707
2026	677	574	722	735	160	512	-8 409	574	-7 132
2027	685	555	700	712	157	468	-7 709	555	-6 578
2028	694	539	684	695	156	432	-7 025	539	-6 039
2029	702	526	671	681	155	400	-6 353	526	-5 512
2030	711	516	663	672	156	373	-5 691	516	-4 997
2031	720	507	657	665	158	349	-5 034	507	-4 490
2032	728	499	653	661	161	328	-4 381	499	-3 990
2033	737	493	652	658	165	309	-3 729	493	-3 497
2034	746	487	652	657	170	291	-3 078	487	-3 010
2035	755	482	653	658	176	276	-2 424	482	-2 528
2036	764	477	656	659	182	261	-1 769	477	-2 051
2037	773	472	659	661	189	248	-1 109	472	-1 578
2038	716	429	609	609	181	139	-501	429	-1 150
2039	640	375	543	542	167	114	43	375	-775
2040	561	319	475	473	154	92	518	319	-456
2041	565	313	477	473	160	85	995	313	-143
2042	569	306	479	474	168	79	1 475	306	163
2043	-3684	-2175	-3052	-3059	-884	-463	-1 578	-2 175	-2 011

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