Offshore wind parks: Let the sea breeze energize your portfolio

Return and Risk from equity and debt investors' perspective

Summary

Green Investments in renewable energies are a strongly growing market. The charm of such investments are long maturities, high revenues from fixed feed-in tariffs and high predictability of income through guaranteed purchase generated power. In addition, renewable energy revenues are typically uncorrelated to other asset classes. Professional investments in renewable energies, however, require a detailed analysis and assessment of the risk return profile. This holds for project sponsors, venture capital, equity and debt investors and is independent from the investment horizon.

Customized cash flow models allow analyzing and modelling wind parks in detail in the planning, the construction, as well as in the operation phase. Thus we may optimize the debt requirements and the return on investment as well as the financing structure of debt and equity. Equally important to a structured investment decision are scenario simulations and sensitivity analyses.

The aim of this study is to illustrate the advantages and the risk return profile of offshore wind park investments by means of complex cash flow models. We compare these investments with other asset classes. The wind park model discussed here is exemplary and entirely based on publicly available information. In this study we cover the following aspects:

- **Valuation of an infrastructure project**
- **Risk and return profile of an offshore wind park investment, both for equity and debt investors**
- **Sensitivity of an offshore wind park with respect to the most relevant risk factors**
- **Comparison of offshore wind park investments to other asset classes.**

1 Wind energy

1.1 Renaissance of wind energy use and current status

1.1.1 The tradition of wind energy

The use of wind power dates back to the medieval times and the ancient world. The commercial use of wind energy by direct drive of machinery – beside the use of water power – began its first period of prosperity in the 16th century. The main purpose then was to grind various grains. The main locations in Europe were wind-rich regions in coastal areas of the Mediterranean, the North and Baltic Sea. Later windmills were almost completely replaced by the use of steam engines, fossil fuels, and electricity.

1.1.2 The renaissance of wind energy use

With Alpha Ventus the first German offshore wind park started its operation officially in April 2010 [1]. We are currently experiencing a renaissance in the use of wind energy. The main reasons are:

1. Limited resources of fossil energy and peak oil

Natural below ground resources of our earth are limited. Fossil fuels such as oil, natural gas, coal and lignite cannot be renewed. There are different estimates on the size of the natural reserves of energy, but fossil fuels will run out in the next 50-200 years, depending on the energy source [2]. According to the chief economist of the International Energy Agency of the OECD, the annual global production peak – or “peak oil” – will be reached in 2020 [3]. The estimates of crude oil inventories - as quoted by the oil-producing countries – are assumed to have been constant for the last 20 years, despite the substantial production during this period. However, some experts are sceptical about these estimates and the actual oil reserves. They assume that ‘peak oil’ has already occurred in 2008.

2. Carbon dioxide emissions and climate change

Since the start of the industrial revolution burning of fossil fuels leads to an accumulation of carbon dioxide (CO_2) in the atmosphere and is thus responsible for global warming and the climate change.

3. Economic and geo-political dependence

The number of oil producing countries is very small. Moreover, they are clustered regionally. This leads globally to a strong regional and political dependency.

4. Technological advances and public funding

Significant technical advances in wind energy conversion occurred in recent years. Special feed-in tariffs and the above factors also helped to foster the use of wind energy both onshore and offshore.

As a consequence, the use of wind energy and renewable energies are promoted in Germany and Europe. It is planned that by 2020 20% of energy demand within the EU is covered by renewable energy sources.

In Germany, the installed capacity of wind power has grown from 55 MW in 1990 to about 25,777 MW in 2009 [4]. At the period the average output per installed wind turbine has grown by more than a factor of ten from 164 kW to 2013 kW [4]. The percentage of electricity, generated by wind energy with respect to the total electricity demand for the top five German local states is summarized in Table 1. According to the statistics Saxony-Anhalt covers almost 50% of its electricity demand by wind energy.

Overall, approximately 7.58% of the electricity consumption in Germany is covered by wind energy. Table 2 shows the total amount of installed wind energy capacity for the five leading German states.

Rank	State	% net electricity demand
1	Saxony-Anhalt	47.08%
2	Mecklenburg-West Pomerania	41.29%
3	Schleswig-Holstein	39.82%
4	Brandenburg	38.12%
5	Lower Saxony	22.78%

Table 1: Percentage of electricity generated by wind energy with respect to total energy consumption in the top five German local states. Source: DEWI GmbH

Rank	State	Installed power (MW)
1	Lower Saxony	6,407.19
2	Brandenburg	4,170.36
3	Saxony-Anhalt	3,354.36
4	Schleswig-Holstein	2,858.51
5	North Rhine-Westphalia	2,831.66

Table 2: Total installed wind power in MW in the top five German local states as of Dec. 31th 2009. The leading state is Lower Saxony with more than 6,000 MW installed. Source DEWI GmbH

1.2 The charm of offshore wind parks

The advantage of offshore wind energy is the high and relatively constant wind velocity at sea as explained in the following:

Figure 1 shows the time series of the average annual wind speed at an offshore location in the North Sea and onshore in Lower Saxony - based on publicly available data from NCEP [5]. The graphs show that the offshore location has an average wind speed which is about 1.2 meters per second higher than the location onshore. Due to the non-linear relationship between the energy amount carried by an air stream and its wind speed - the amount of energy increases with the cube of the wind speed – 16% higher offshore wind speed leads to an almost 60% higher theoretical turbine output. This is an important aspect for the use of offshore wind parks.

Figure 1 shows another interesting aspect. Over a period of 50 years an average increase in wind speed of 0.6 meters per second is observed both onshore and offshore. Much higher yields may be expected provided this trend continues.

The increasing employment of offshore wind turbines in the 5 MW class and higher will continue the increase in the average installed power per wind turbine in Germany. This trend has already been mentioned in section 1.1.

Alpha Ventus is in operation since April 2010. In the North and the Baltic Sea further 24 offshore wind parks have already been approved [6]. The investment volume for these projects is a double-digit billion number. From an investor's point of view, a wind park could be very interesting. This is due to the high feed-in tariff of 15 cents/kWh and a high predictability of income due to guaranteed purchase of the generated energy. The wind park returns are not correlated to other asset classes. Wind parks therefore may help to diversify an investment portfolio. The installation of offshore wind parks is a greater technological challenge as compared to onshore parks and results in higher construction and maintenance costs. But this is compensated - as illustrated above – by significantly higher average wind speeds and wind turbines with much higher capacity than onshore.

An overview map of German wind parks in various stages of approval in the North and Baltic Sea is shown on the website of the BSH [7].

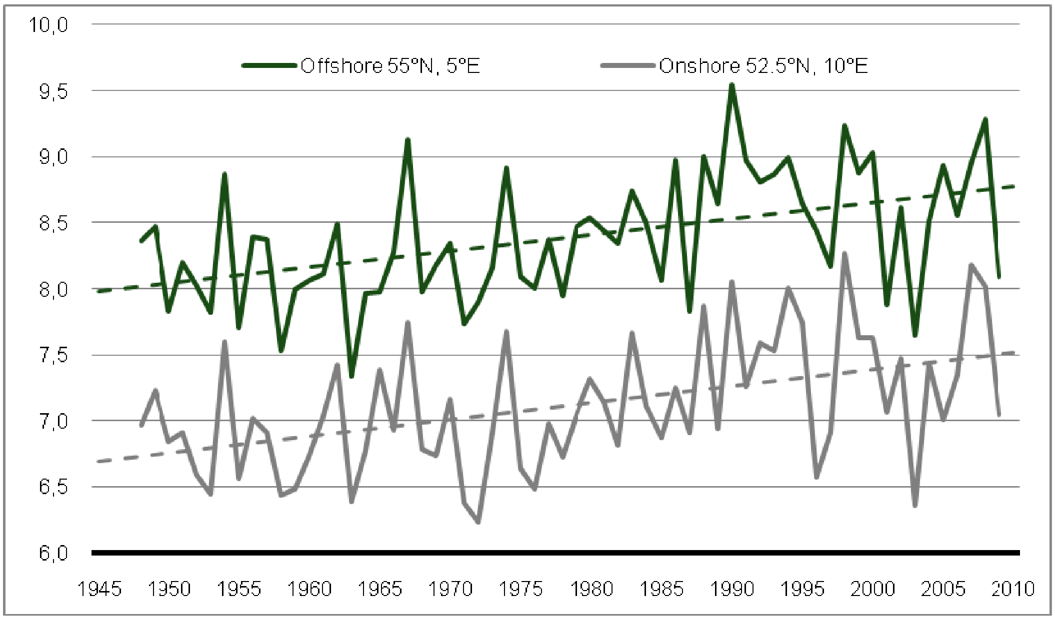

Figure 1: Average annual wind speeds (in meters per second) at an offshore (dark green) and an onshore location in the North Sea and Germany (gray) as a function of the calendar year. The dashed lines show the second-order regression. The GPS coordinates of the position are given in the legend. Source: NCEP

2 Cervantes: A typical offshore wind park

2.1 Technical data of Cervantes

As an example we model a typical wind park, called 'Cervantes'. Table 3 shows the technical details of the model park. The basis of the modelling is public data only, such as from the BSH. The park consists of 80 turbines with a nominal output of 5 MW each. The combination of 80 times 5 MW turbines is the most common wind park layout based on the current permits [6].

Description	Value
Number of turbines	80
Output per turbine in [MW]	5
Park output in [MW]	400
Diameter of rotor in [m]	120
Hub height in [m]	100
Construction period in [years]	3
Operation period in [years]	25
Feed-in tariff in [cent/kWh]	15

Table 3: The technical data of Cervantes, a typical wind park model. Source: BSH

For simplicity, we assume that wind conditions are comparable to Alpha Ventus and the research platform FINO 1 in the North Sea [8].

The offshore wind park project Cervantes consists of two main phases: the construction and operational phase. Both are discussed in detail in the following.

2.2 The construction period

The construction of an offshore wind park is technically and logistically far more complex as compared to that of an onshore park. The challenge increases with following conditions:

1. Increasing distance from the mainland
2. Increasing water depth
3. Sites with adverse weather conditions such as high waves and storm frequency

The first point affects the logistics and transport, causing essentially higher transportation costs. In addition, a greater distance to the mainland requires higher cost such as the connection to the grid. However, the grid connection must be provided by the network operator and not the developer. Increasing water depth requires a higher material usage and higher costs in the static and the establishment of the foundations. The third point calls for a more elaborate design of the park, in addition it causes a higher planning effort and an increased risk of delays in the construction phase. Besides, all three factors affect the operating costs.

The main components of an offshore wind park are:

1. Foundations
2. Nacelle with generator and gearbox and rotor blades
3. Inner park wiring
4. Transformer and service platform
5. High-voltage submarine cable to the mainland and grid connection

At present, various foundation systems are in use respectively planned to be used. There are different types of steel foundations like: single pods, tripods and jackets and one type of reinforced concrete foundation, a so-called gravity foundation. A different deployment procedure is required for each foundation type. Typically the foundation carries a tower with the wind turbines. Currently offshore wind parks are designed for 5 MW turbines; however there are already plans for 7 MW turbines. Alpha Ventus uses 5 MW turbines from Repower and Areva Multibrid [1]. Wind turbines are connected to the transformer station by the inner park wiring. At the transformer platform the power is transformed to high-voltage and transmitted via a submarine cable to the mainland. The high voltage cable and the connection to the transformer station are usually in the responsibility of the network operator. The transformer platform may also be used for maintenance and logistics. Depending on the distance to the mainland it can also offer accommodation for service personnel. The operating license for a wind park is linked to a number of requirements with regard to safety, environmental protection and navigation rules. The construction permit is subject to a number of survey reports.

The construction period of the pioneering project Alpha Ventus was about three years. It is expected that due to technological innovation and experience, a construction period of three years is realistic for even larger offshore wind parks located further away from the mainland. The hot commissioning of the individual turbines is carried out gradually in the final phase of the construction period. Revenues are already generated during this phase that may subsidies the construction cost.

2.3 The operating period

With the hot commissioning of the last wind turbine the park enters the operating phase. The overall operating period of the park is regulated by the operating license. In Germany it is typically 25 years. A further extension of the license is subject to approval by the BSH [6]. In the following we describe the operating period in more detail.

2.3.1 Revenue

The revenues of the electricity generation are governed by the Renewable Energy Act (EEG). Under the current legislation, offshore wind turbines in Germany are compensated with 15 cents per kilowatt hour (kWh), if the start of operation is before January 1st 2016 (EEG § 31). The tariff is guaranteed for 12 years and increases by 1.7 months for each additional full meter beyond the reference water depth of 20 meters. In addition the tariff period is extended for another 0.5 months for each full mile from the coast beyond 12 nautical miles.

Example: A wind turbine which is located 50 nautical miles from the coast at a location of 30 meters water depth could benefit from guaranteed feed in tariff of 15 cents/kWh for a period of 15 years (12 years + 10 x 1.7 months + 0.5 x 38 months).

Technically, the tariff period for each turbine of the wind park is calculated individually and may vary within the park. After the fixed tariff period the revenues are subject to the electricity spot price. The electricity generation may be marketed directly by the wind park operator. In addition, the operator also holds the emission rights which represent a further value. The revenues beyond the fixed EEG tariff period have to be estimated based on factors like inflation, energy prices and the electricity demand and supply equilibrium.

2.3.2 Wind yield estimation

The actual annual energy yield of the wind park is determined by two factors: the technical availability of the park and the annual variation in energy output.

Typically the whole wind park does not run on 100% availability due to scheduled and unscheduled down times and maintenance works at the individual turbines and wind park components. The risk of an unexpectedly low availability is - to a large extent – hedged by full maintenance contracts of the major parts, insurance coverage and manufacturers guarantees.

For the model park Cervantes we do not hold a wind report with a real yield estimate. We therefore make a number of assumptions about the annual energy yield and its uncertainty. From the published data of Fino [8] ⬀ we assume an average annual wind speed of about 10 meters per second and a theoretical power curve of the turbine. To be on the save side, the theoretical value is discounted by 5%. As a result we assume an expected number of 4,330 annual full load hours for Cervantes. The full load hours describe how many hours the park must run under full load in order to produce the same energy amount estimated under consideration of all influencing factors.

Assuming revenue of 15 cents/kWh and three different flat-rate deduction of 0%, 5% and 10%, that may include all negative factors such as losses and reduced availability, we arrive at a total annual energy yield in GWh and corresponding revenues in €. Table 4 summarizes the results for the three different deductions mentioned above.

Deduction in [%]	0.0	5.0	10.0
Annual energy yield in [GWh]	1,732	1,645	1,559
Full load hours per year	4,330	4,114	3,897
Annual revenue in [€ m]	259.80	246.81	233.82

Table 4: Theoretical annual power output of Cervantes for three different flat-rate reductions in the amount of 0%, 5% and 10%, and assuming average wind speed (P50, see explanation below).

2.3.3 Uncertainty of the wind yield

Each turbine type has a characteristic power curve describing the dependence of the power output as a function of wind speed. At the so-called ‘rated wind speed’ the turbine reached its maximum power. At the maximum wind speed the turbine has to be switched off for security reasons. Below the minimum wind speed the turbine stalls. Uncertainty in wind yield by low wind or by stormy periods is quantified by independent wind reports such as by DEWI [9].

The wind report takes into account the individual wind conditions at the site, properties of the turbines and all other specific factors such as shading, wave motion, etc. The wind report typically produces wind yield forecasts, which do not fall below a given probability of 50%, 75% or 90% (P50, P75 and P90 scenario). The basis of a wind report is the historical distribution of wind speeds at the site. A wind report provides the basis for assessing the uncertainty of the income stream. Assuming a typical volatility in the wind speed, we derive the energy yield in a similar way to a wind report for a P90 scenario. Table 5 (below) summarizes the results.

Beside the revenues, the operating costs play an important role in the operational phase.

2.3.4 Operating costs

On the cost side the most important positions are:

1. Maintenance
2. Operation management
3. Insurance
4. Consulting and administrative costs
5. Own energy consumption
6. Provisions for decommission and repair

Deduction in [%]	0.0	5.0	10.0
P90 full load hours per year	3,886	3,692	3,498
P90 annual revenue in [€ m]	233.16	221.46	209.82

Table 5: Theoretical annual power output of Cervantes for three different flat-rate reductions in the amount of 0%, 5% and 10%, and the assumption that the wind speed will not fall below a certain level with a confidence of 90% (P90 scenario).

Typically, contracts for maintenance, insurance, etc., are long-term and the costs are linked to an inflation index. Therefore, the difference between expected and realized inflation is one source of uncertainty in the estimation of the operating costs. In addition to the operating costs the capital costs for interest payment and repayment must be considered. If all costs are given or can be estimated and the dependencies between the costs are known, the wind park can be modelled in detail both in the construction and the operational phase. Due to the exemplary character of Cervantes such a detailed view is not required. Instead, we assume that the expenditures in the operational phase are a fraction of the total revenues. The estimates for different cost components of offshore wind parks are based on a study presented at the Husum Wind 2007 [10]. Accordingly, the total running costs account for about 25% to 35% of revenues. We therefore assume expenditures in the amount of 25%, 30% or 35% of total revenues and combine it with the earnings estimates shown in Table 4.

2.3.5 Revenue requirements in the operating phase

In the operating phase, the revenues have to cover the ongoing operating costs and the debt service which includes interest payments and redemption. The remaining cash flow – after provisions and tax - is distributed as a dividend payment to equity investors. Debt is structured in several tranches with different seniority and interest rate level. The financing can be tailored to the capital market requirements and for different risk-return profiles. A special reserve account protects the debt service of the wind park. In addition there are provisions for decommissioning at the end of the operation phase. They are requested as part of the operating licenses.

Regardless of debt or equity, the realized return on investment is of central importance to an investor. Whether a wind park investment shows an adequate risk-return profile may only be decided at the end of the investment horizon. However, this is not practical. Therefore, appropriate tools are required to assess the risk and return of such an investment. In the following section the return and risk profile of Cervantes is thoroughly analyzed and optimized.

3 Offshore wind park investments from investors' perspective

There are different options to invest in offshore wind parks. The key to investors is the return perspective and the corresponding risk profile. The most important investment types are described below.

3.1 Key parameters of an offshore wind park investment

The expected return affects the investment strategy. The following questions have to be considered by an investor:

1. Investment phase: construction or operational phases?
2. Investment type: equity investment, senior or subordinated debt?
3. Investment horizon: short, medium or long term?

3.1.1 Investment phase

Depending on the risk appetite an investor can invest at a very early stage of a project: the planning and construction phase, or at completion and transition into the operational phase. The financing of the first two phases have venture capital character. The investor is exposed to much higher risks like the completion risk. It is therefore expected to earn an adequate return. In the operating phase, the construction has already been completed. High predictability of income and costs is provided through guaranteed purchase of the generated power, fixed tariffs and long term maintenance and insurance contracts. Returns are therefore lower than for early stage investments.

3.1.2 Investment type

In principle it is possible to invest either in debt or equity. In practice, however, there are a number of hybrid investment forms. A prerequisite of debt investors is a sufficient capital base, both in the construction and in the operational phase. With the completion of the wind park construction, short term baby bonds are replaced by loans with much longer maturities. Another option is to sell the wind park at completion. In that case the funding could be met entirely by equity investors, such as through a pension fund. In case of a debt funding a balanced equity debt ratio is demanded by debt investors. Debt can be issued in tranches of different seniority. Debt with the highest seniority is called the senior debt. Interest and principal payments of senior debt are serviced prior to so-called subordinated or junior debt. Tax is typically paid before repayment but after interest payments of senior debt. The remaining proceeds are - after deduction of taxes and all operating costs - paid out as dividends to equity shareholders. The level of interest rate varies with the level of debt seniority. The higher risk of the subordinated debt is rewarded with a higher risk premium as compared to the senior debt. In addition, lenders typically demand static guarantees in the form of a reserve account that may absorb any short term liquidity shortage and dynamic guarantees. Here, the debt service coverage ratio (DSCR) has become the standard measure. The DSCR is the ratio of earnings before interest, taxes and amortization divided by the debt service, which consists of interest payment and repayment. In project financing debt investors typically demand DSCR values in the range of 1.1 to 1.5. Clearly, senior debt requires a higher value than subordinated tranches.

3.1.3 Investment horizon

We may distinguish between:

1. Short term funding in the range of 3 months to 3 years.

2. Medium term funding in the range of ten to fifteen years

3. Long term funding for maturities above fifteen years

The definition does not follow the typical money and capital market conventions, but is adapted to project finance. Short-term investment in the construction phase is typically in the form of equity or baby bonds. The debt and interest rates are refinanced several times during the construction period. The maturity is in the range of 3 to 6 months. The reason for the short maturities is the strong dependency of the borrowing costs on the construction progress. The initial funding is covered by equity. After the equity is invested, debt with a specific interest rate and maturity is injected. Often equity investors also cover parts of the debt requirement in the construction phase in the form of shareholder loans.

3.1.4 Maximum return versus maximum turnkey

Investors pursue different investment objectives depending on the investment horizon and risk tolerance. Equity and debt capital investors demand a maximum return for a given level of risk. Typically the return on equity rises with an increasing debt to equity ratio. Equity investors therefore aim at a maximum return on investment *and* a maximum debt to equity ratio. On the other hand debt investors demand a reasonable return on investment and a minimum risk buffer in the form of a predetermined minimal DSCR and the existence of a reserve account. This results indirectly in a minimal level of equity which facilitates the required DSCR.

3.1.5 Costs versus value

In the tug of war between equity and debt investors, there is another force, the maximum value of the wind park, also called the turnkey. From the point of view of a project developer, who builds a wind park and plans to sell it at the start of operation, the park should achieve the highest possible selling price. This price must exceed the total construction costs, i.e. the investment costs, plus all financing costs and all other costs of the construction phase. However, an investor who purchases a wind park at completion is only interested in the value or turnkey of the park, rather than the construction costs. The turnkey is the present value of the expected cash flows from the wind park operation.

Please note that the first wind turbines are commissioned in the construction phase and produce revenues that may add up to tens of millions of €. These revenues are earned by the developer and may reduce the total costs but may also reduce the operation period of the park and thus may have a negative impact on the turnkey.

With the help of sophisticated cash flow models and optimization tools, the turnkey of a wind park is maximized for the given set of wind park parameters. The optimization is achieved by the right choice of the debt to equity ratio and an optimized repayment structure of the debt. For Cervantes such an optimization is performed and illustrated in the following.

3.2 The key data for financing of Cervantes

The starting point for the analysis is Cervantes in the operational phase. The aim of this section is to maximize the turnkey of Cervantes constraint by the return on equity demanded by the equity investor and the maximum level of risk allowed by the debt investors and measured by the DSCR.
Table 3 summarize the most important technical data of Cervantes.

Table 6 now shows the key data for debt and equity financing. We model a wind park with a senior and a junior tranche and equity. The tranches demand different interest rates and DSCR values. The level of senior debt interest rate takes into account the participation development banks like KfW or EIB. The junior tranche is typically funded by a consortium of commercial banks.

Description	Value
Senior debt interest rate in [%]	5.5
Junior debt interest rate in [%]	6.5
Return on equity in [%]	11.0
Maturity of debt in [years]	15
operation period in [years]	25
Inflation operating costs in [%]	2.0
Inflation electricity price [%]	3.0
DSCR Senior	1.5
DSCR Junior	1.3

Table 6: The key financing data of Cervantes.

The turnkey of Cervantes is driven by the operating costs, the electricity revenues and all the other key financing parameter. The turnkey is maximized under the following scenarios of revenues and operating costs. Here, S1 is the scenario with the highest revenues and the lowest operating costs, for scenario S3 it is the other way round and S2 is between scenario S1 and S3 in terms of costs and revenues. Table 7 illustrates the three P50 scenarios. The percentages operating costs refer to the initial revenues of each scenario. In subsequent years, the operating costs increase with the inflation rate (see Table 6).

Scenario	S1	S2	S3
Annual electricity revenues [€ m]	259.80	246.81	233.82
Initial relative operating costs in [%]	25.00	30.00	35.00
Initial operating costs in [€ m]	64.95	74.04	81.84

Table 7: Three different scenarios for electricity revenues and operating costs for Cervantes. The initial relative operating costs refer to the annual electricity revenues for the P50 scenario.

3.3 Results

3.3.1 Turnkey

For each scenario, the wind park is optimized with respect to the maximum turnkey under the risk constrain (DSCR 1.5 for senior and 1.3 for junior debt). Therefore no other financing structure with a higher turnkey exists, which satisfies the conditions shown in Table 6,. The term of the debt is 15 years, the total operating time and thus the basis for the equity maturity is 25 years. Here we follow a typical requirement that the debt financing runs only during the guaranteed feed in tariffs and must be met under the P90 scenario.

Scenario	S1	S2	S3
Turnkey in [€ bln]	1.818	1.578	1.353
Equity ratio in [%]	21.01	21.47	21.98
Senior debt ratio in [%]	57.93	57.49	57.17
Junior debt ratio in [%]	21.06	21.04	20.85
Senior & junior debt ratio in [%]	78.99	78.53	78.02

Table 8: The major key financial results for Cervantes for a maximum turnkey under three different scenarios. The ratios of equity and debt are given with respect to the turnkey.

The equity financing is optimized under the P50 scenario. The main results for the three different scenarios are summarized in Table 8. It illustrates two important results:

1. As expected the turnkey falls with falling revenues and rising operating costs.

2. Independent of the revenues and the operating costs, return on equity and the risk constrains demanded by the investors are met.

The two results are discussed in more detail in the following.

1. The difference in turnkey with respect to S2 is about minus €240 million for S1 and plus €225 million for S3. The difference is significant less than the expected difference in net income during the operating phases calculated from the difference between electricity revenue and operating costs and ignoring the inflation and interest costs. The difference in net income with respect to S2 is minus €520 million for S1 and plus €486 million for S3. This illustrates that the shortfall in net income translates only to 50% into a fall in turnkey. This is very good news for an investor, because the sensitivity of the turnkey caused by a variation in revenue and expenses is only about half the size implied by the fluctuations of the net income. The reason for this observation is the discounting effect of cash flows and the time-value-of-money. Cash flows earned in the distant future, have a very low present value. For a maturity of 25 years, this effect is quite noticeable.

2. The second result is also very positive for investors entering at the start of the operational phase. It demonstrates that demanded investment objectives can be met if the turnkey is adjusted accordingly and vice versa: The Turnkey can be adjusted such as the demanded debt and equity return and the required DSCR are met. Overall, the ratio of debt and equity to the turnkey is relatively stable at about 79% and 21%, respectively. We notice a slight increase in the equity ratio from 21.01% to 21.98% for S1 with respect to S3. This is plausible, as falling revenues demand a higher equity ratio.

3.3.2 Time dependent behaviour of debt and equity

Figure 2 shows the outstanding debt for the two tranches obtained from the optimization process for scenario S2. The debt is redeemed over a period of 15 years. The redemption structure does not necessarily follow a linear or annuity structure, but is optimized with respect to the following factors: revenues, operating costs, target DSCR and target return on equity.

Interest rate payments and the distribution of dividends paid to the equity holders are shown in Figure 3. Dividends are paid from the second project year onwards. After the complete redemption of debt in project year 15 dividend payments strongly increase.

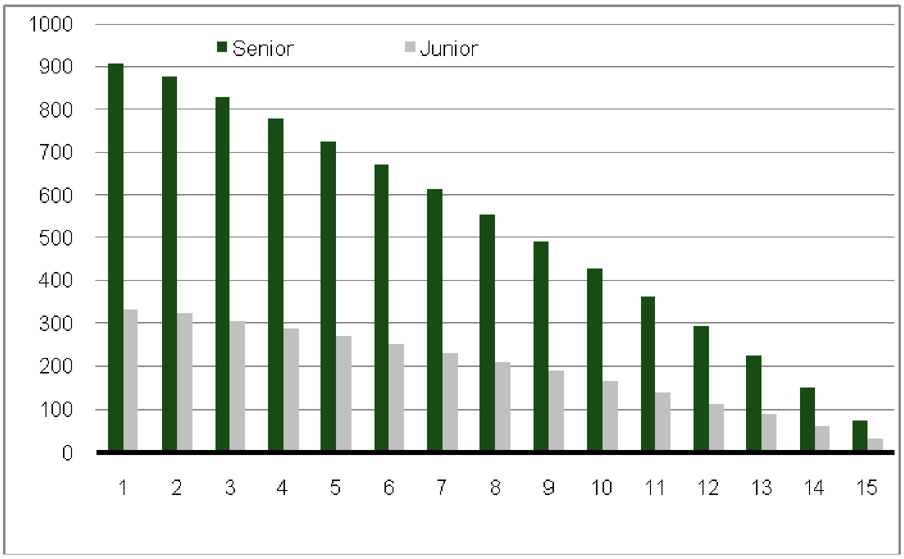

Figure 2: Time dependent behaviour of outstanding debt in € million as a function of the project year for senior debt (dark green) and junior debt (grey).

The two peaks of dividend payments in project year 16 and 25 are one-time effects. One year after the complete redemption of debt in year 16, the reserve account that has been held to secure the debt payment is distributed to the equity investors. The reserve account holds the debt service equivalent to interest and nominal payments for six months. The model holds an account for decommissioning. This account is required as part of the operating license. We assume, however, that the salvage value of the park covers the decommissioning costs. Therefore, at decommissioning of the wind park the provisions of the decommissioning account are distributed as dividend. In project year 16 the feed-in tariff expires and the electricity is sold at the current spot price. Electricity revenues rise linearly due to the inflation rate of 3%. The operating costs rise by 2%. In project year 17, the dividends are higher than in the following years, this is due to a tax effect.

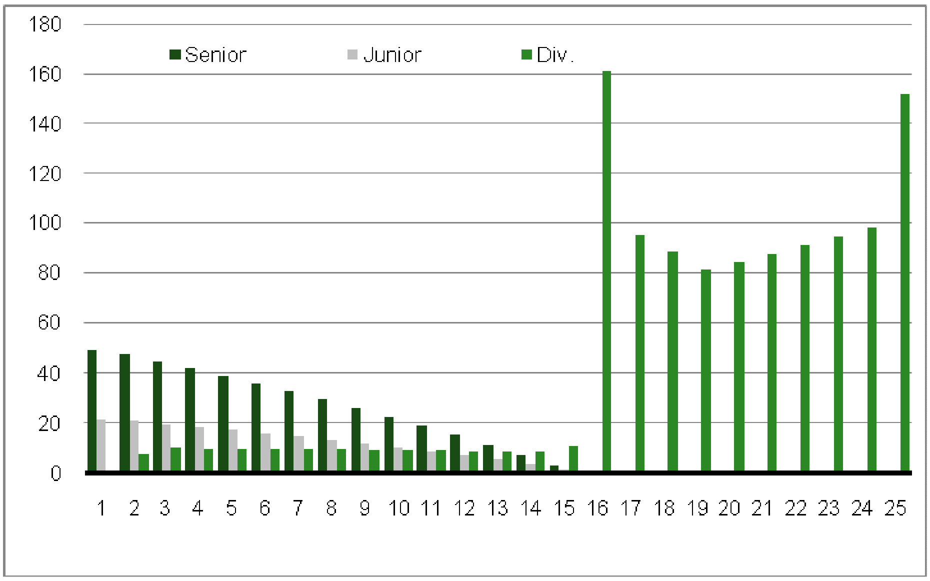

Figure 3: Interest rate payments in € million and dividend payments in each project year for senior debt (dark green), junior debt (grey) und dividends (bright green). The debt financing ends in project year 15.

Project year 17 is the last year where depreciation is claimed.

3.3.3 Tax effects

The return on equity and the interest rate demanded in Table 7 are, from an investors' perspective, 'before tax' returns. Tax rates of investors depend on the particular legal entity and the specific tax situation and are therefore neglected. On the level of the project company, however, corporate tax and trade tax are applicable. Both types of taxes are taken into account in the cash flow model assuming typical values for German tax and depreciation scheme. Our results are therefore after tax returns on the project company level.

4 Risk and sensitivity analysis of wind park investments

In this section a sensitivity analysis is performed. We examine the impact of revenue fluctuations on the DSCR and how the turnkey depends on factors such as interest rates for debt and equity, the wind park operating period and revenues. A sensitivity analysis is a typical risk management approach to quantify market risk for financial products like fixed income instruments, derivatives and structured products. Our reference is scenario 2, as described in section 3.2.

4.1 Sensitivity of the DSCR value

The DSCR is the risk buffer of a project. Investors typical demand certain DSCR values. For Cervantes, we set the DSCR to 1.5 for the senior tranche and to 1.3 for the junior tranche. In the following we analyze the impact of an annual 3% revenue loss on the realized DSCR. Figure 4 shows the DSCR values before and after the revenue loss for the senior and junior tranche as a function of the project year.

The decline in revenues leads to a moderate decrease of the minimum DSCR from 1.5 to 1.43 for the senior tranche. For the junior tranche the observed DSCR decline is larger and falls from 1.3 to 1.1. Here the DSCR approaches the critical value of 1.0 where after tax cash flow is entirely consumed by the debt service. The return on equity falls from 11.0% to 9.81%. Table 9 summarizes the results.

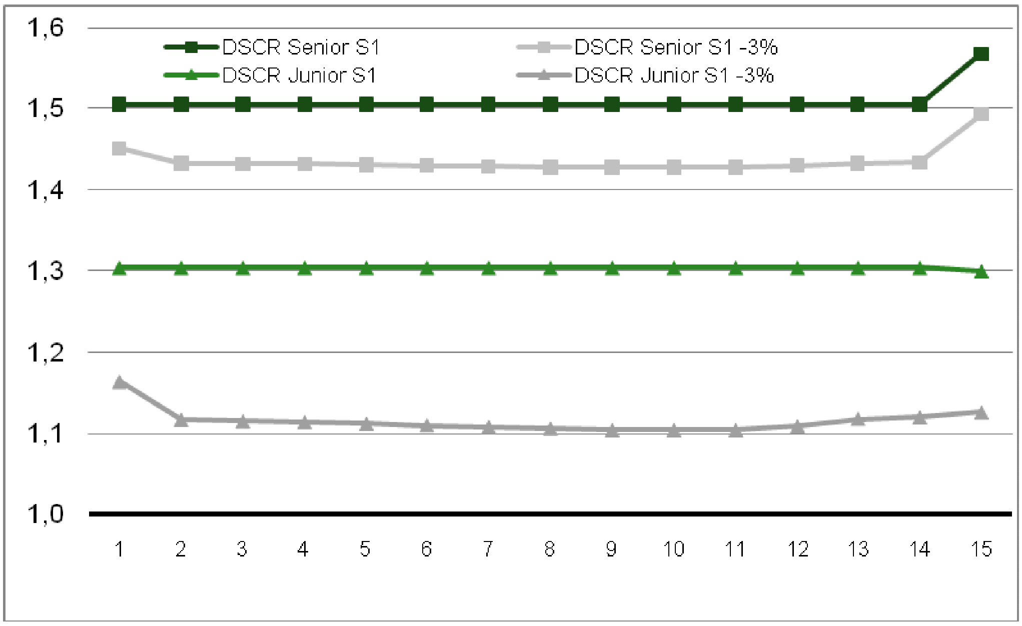

Figure 4: DSCR values for senior debt (dark green), junior debt (bright green) before and after an annual revenue loss of 3% (grey) as a function of the project year.

Key figure	Value
Change min. DSCR senior	1.427
Change min. DSCR junior	1.104
Average DSCR senior	1.435
Average DSCR junior	1.115
Equity return in [%]	9.81

Table 9: Impact of an annual 3% decline in revenues on the DSCR values and return on equity for scenario 2.

4.2 Basis point value or the impact of required rate of return

One of the most important risk measures for financial instruments carrying interest rate risk is the basis point value or bpv. One basis point is 0.01%. The bpv measures the change in present value of an instrument with respect to an interest rate movement of one basis point. For assets the bpv is typically negative, i.e., the present value falls for rising interest rates, because an investment product could earn a higher return with rising interest rates. The bpv of Cervantes under scenario 2 is €1.2 million. If interest rate for debt and equity rises by 0.1% (10 basis points) the turnkey falls by €12 million. Here, the value of the equity falls by about €4 million senior and junior debt by €8 million. Similarly to the above calculation the bpv may be obtained for debt and equity separately. The bpv of a wind park may be easily compared with other investment products such as bonds.

An alternative way to calculate the bpv is via the concept of duration. The duration is determined from the given cash flow structure of the wind park and is compared with the bpv calculated above. The duration of the cash flows from interest, dividend and repayment is 9.2 years, i.e. the present value weighted stream of cash flows is equivalent to a single payment after 9.2 years. Given the duration and the turnkey of the wind park an alternative bpv of €-1.45 million is obtained. As a result it is obvious that the simple linear approach of the concept of duration leads to a slight overestimation of the risk as compared to the above calculation.

4.3 Theta or the impact of the operating period

Another important factor that impacts on the key wind park figures is the operating period of the park. The influence of maturity on the value of financial instruments is typically expressed by the Greek letter theta (τ). Changing the operating period we may distinguish two different cases:

1. The operating period is changed for a fixed financing structure. This is typically the case when the total operating period changes during the operating phase.

2. The financing structure of the park is optimized with a different total operating time.

First, we examine the impact as described in 1. This is accomplished by reducing the operating period of Cervantes from 25 years by 1 year, all other parameters remain unchanged. When wind revenues of project year 25 are missing, only return on equity is affected, because the debt is already completely repaid after 15 project years. Our simulation shows that the reducing in the term causes a drop in return on equity by 26.5 bp. The return on equity falls from 11% to 10.74%. This corresponds to a decline in the present value of equity of approximately €7.65 million or 2.26%. Since the debt is not affected by the reduction of term, the turnkey falls by the amount of equity loss only. Conversely, if operating period is extended by one year, an increase in equity value in the same order of magnitude can be expected.

The situation is slightly different when the wind park is optimized with a shorter operating period. Now, the same return on equity is demanded, but over a shorter period. This requires the turnkey to fall. The debt service is also affected. Our calculations show that the turnkey falls by approximately €12 million. The equity falls by €11 million and the debt by €1 million. The ratio of equity to turnkey falls by 0.5%. The total loss in turnkey is higher than for case 1. This is the other side of the coin: In order to hold the required return on equity of 11% a higher decline in the turnkey has to be accepted.

4.4 The impact of revenues and the elasticity

Another important risk variable is the influence of the net income on the turnkey. The analysis shows that an annual decrease of 0.1% in the income over the life time of the park causes a decrease in the turnkey of 0.196%. Here, the operating costs are held unchanged. Defining the elasticity as the ratio of percentage change in turnkey divided by the percentage change in annual net income, we obtain a value of 1.96. The elasticity is larger than one. That means that a relative percentage change in the annual net income translates in an almost twice as large change in the turnkey. The result is independent whether the change in net income is caused by lower feed-in tariffs, lower wind yields or higher operating costs.

The sensitivity measures calculated in this section are summarized in Table 10.

Key figure	Value
bpv in [€ m]	-1.20
Theta (-1 year) in [€ m]	-7.65
Theta (-1 year) in [bp]	-26.50
Elasticity	1.96

Table 10: The most important sensitivity measures of Cervantes: Basis point value (bpv), theta in € million with respect to the turnkey and in basis points and cost elasticity. All results are based on scenario 2.

5 Risk analysis and comparison with other investments

Offshore wind parks hold a number of characteristics that differentiate them from other investments. The most outstanding features are:

1. Guaranteed purchase of generated electricity

2. Guaranteed feed-in tariffs for a period of 15 years and longer

3. No dependency on economic factors

4. Income fluctuations are only caused by:

   a. fluctuation in the wind yields
   b. operating and maintenance costs
   c. technical risks

The impact of earnings volatility is mitigated by:

1. Wind report: the wind report provides an independent assessment of both the expected wind yields and its volatility. Both factors are considered in the modelling.

2. The wind park operation is typically managed by long-term full service maintenance contracts. The costs are therefore fairly stable and predictable. In the long-term contracts costs are often indexed by inflation. An unexpected high realized inflation as compared to the forecasted inflation poses a certain risk on the operating costs. However inflation risk may be hedged through the use of derivatives.

3. The technical risks include all critical components of the wind park like turbines and in particular the gearbox and blades, stability and wear of foundations and all components of the power transfer. Critical factors are wear and tear, adverse weather conditions and corrosion. The transfer and mitigation of technical risks are achieved by three instruments: manufacturer warranties, full service maintenance contracts and insurance policies.

5.1 Capital market risk

In the category of capital market risk the wind park is exposed to interest rate and credit risk. Here, foreign exchange rate risk is neglected.

5.1.1 Interest rate risk

Senior and junior debt financing is exposed to interest rate risk. The risk of present value fluctuations of a fixed coupon financing can be hedged by means of a payer swap. As a result the investor carries cash flow risk of the variable interest rate payments.

5.1.2 Credit risk

There are three different provisions for senior and junior debt investors to manage the credit risk of project:

1. Reserve account

2. Minimum DSCR and cash flow buffer

3. Structuring in tranches

1. The reserve account protects the short-term liquidity of the wind park and is held exclusively for the debt service. The reserve account typically holds, interest and principal payments for three to six months. It serves to weather a temporally cash shortage caused by unexpected high expenses or low revenues. In the case of debiting the reserve account to cover the debt service, a subsequent dividend payment to the equity investors will be made only after the reserve account has been replenished to the required level.

2. The DSCR is the medium-and long-term risk buffer of a project financing. The request of the debt investor for a minimum DSCR ensures that the debt service consumes only a certain fraction of the earning. Lower than expected earnings are thus carried first by the equity investors and do not affect the debt service. Depending on the seniority of the debt, DSCR values in the range of 1.5 to 1.3 are requested by debt investors.

3. The structuring in tranches of different seniority represents an additional safety mechanism for debt investors. Here tranches of higher seniority are serviced first and are thus secured with a higher DSCR. Higher seniority comes at a price of lower returns.

5.1.3 Rating of a project finance structure

If investors require a rating based on an internal or external rating process, the above provisions play an important role in the overall credit rating. There are minimum requirements to achieve a credit rating of at least investment grade such as a reserve account that holds the equivalent amount of 6 month debt service, and a corresponding DSCR in the range of 1.5-1.3 depending on the seniority. Another important rating relevant factor is the expected revenue volatility. Additionally, factors such as further provisions like covenants and the experience and quality of management affect the credit rating.

5.2 Comparison of return on investment

Wind park investments must compete with other investments in terms of risk and return in order to be attractive to investors. Investments that are suitable as a reference are corporate bonds, asset-backed securities (ABS), project bonds or profit-participation certificates with similar maturity and risk profile. There are two steps in order to derive a reasonable return on investment:

1. Determine the risk-free interest rate which matches the maturity.

2. Determine the adequate risk premium (credit spread), which reflects the credit risk of the investment.

The target return is the sum of market return (1) and credit spread (2). The risk-free interest rate is given by the swap rate of matching maturity. The risk premium may be obtained from credit default swap rates (CDS) of similar maturity. The estimated return of wind park investments can be directly compared to publicly traded financial instruments. The information system Bloomberg offers a very extensive database for the above yield comparison. The relevant reference parameters are instrument maturity and risk (credit rating).

6 Summary and outlook

This study illustrates the basic building blocks of wind parks for the hypothetical park Cervantes and how sophisticated cash flow models allow calculating the turnkey and optimizing the capital structure for debt and equity.

The foundation of this study is a detailed mapping and modelling of the construction and operation phases of the project. Here, the expected return and risk tolerance is not the result, but the starting point of the structuring. The described process model puts a potential investor in an active position within in the investment process. It empowers him to negotiate his terms with respect to return and risk. In the same way, the approach bolsters the sponsor to disclose and to present the project to potential investors in a transparent way.

The presented model and the considerations are not limited to offshore wind parks. In a similar fashion it is suitable to onshore wind parks, photovoltaic, solar thermal and other renewable energy projects. In addition, the generic version of our model analyzes and optimizes any infrastructure project in the planning, construction, and operation phase.

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