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Regulating Future Offshore Grids: Economic Impact Analysis on Wind Parks and Transmission System Operators

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REGULATING FUTURE OFFSHORE GRIDS: ECONOMIC IMPACT ANALYSIS ON WIND PARKS AND TRANSMISSION SYSTEM OPERATORS

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Abstract

The increasing development of offshore wind parks in the European offshore territory may lead to meshed offshore grids in which each wind park might be connected to several countries. Such offshore grids could be subject to various regulatory regimes, depending on the degree of cooperation between the respective countries. This study focuses on how investors in wind parks and transmission systems are affected by the choice of regulatory regime in offshore grids with one to four countries connected. In order to capture the uncertainties related to the exposure to market prices as well as risks related to line failures, we develop a stochastic model for an exemplary wind park and offshore grid. This yields the real option values of operational flexibility from additional connections. Simulation results show that the choice of regulatory regime, including market access and pricing rules, can have a significant impact on the value of a wind park and on the value of the interconnection capacity in the offshore grid. The impact can both be positive and negative, implying a complex incentive structure for the involved actors. If contrary effects are not reflected in the remuneration level of a wind park, for example in the price premium level, investment incentives could either be diminished or the wind park could incur windfall profits. Both cases are socio-economically suboptimal as they may pose additional cost to the system. Policy makers should consider these findings when designing the regulatory regime and level of support in an offshore grid in order to maintain an effective and efficient development of offshore wind in Europe.

Keywords

Economic impact analysis; Offshore grids; Offshore wind; Regulatory regime

1 Introduction

Offshore wind energy is one of the cornerstones for achieving a higher share of renewable energy sources (RES) in a number of coastal European countries. Until now, the connection of offshore wind parks is mainly pursued from a national approach. However, with the increasing number of offshore wind parks in the European offshore territory, the interconnection of offshore wind parks in meshed offshore grids with simultaneous connection to more than one country is coming more and more into focus. An early example is the Kriegers Flak project in the Baltic Sea where Denmark, Germany and possibly Sweden at a later stage collaborate on a common offshore node. Similar projects are also under discussion for the Irish Sea and for the North Sea. A study on the latter demonstrated that a common connection of offshore wind parks as well as further connections between them can lead to large cost savings and extra benefits from electricity transmission of up to 21 billion Euro for the North Sea region (deDecker and Kreutzkamp, 2011).

An offshore grid would enable a joint system optimisation across wind parks, interconnections and electricity markets. This is expected to be of socio-economic benefit, amongst others thanks to infrastructure cost reductions, increase in security of supply for all participating countries, enhancement of trade between markets, and benefits from an improved market integration of the fluctuating wind energy (deDecker and Kreutzkamp, 2011).

Offshore grids could be subject to various regulatory regimes, depending on the preferences as well as the degree of cooperation between the participating countries. More specifically, the countries would have to agree on the regulation of market access for the interconnected offshore wind parks and would have to design the pricing rules. Also the level of cooperation regarding renewable support and in some cases the choice of support scheme for the offshore area are to be considered.

Research in the field of offshore grids for wind energy is increasing: beside the aforementioned study by deDecker and Kreutzkamp (2011), research is undertaken on technical level, e.g. by Trötscher and Korpås (2011) regarding an optimal topology of an offshore network, as well as on regulatory level, where Roggenkamp et al. (2010) analyse offshore electricity grids and their potential implementation in respect to market and regulatory aspects. Woolley et al. (2012) analyse legal aspects of offshore grids, including the cases where an offshore wind park is in addition to its 'home' country also connected to one other, and where it forms part of a meshed offshore grid. Schröder (2012) shows that participation in national balancing markets constitutes a main part of the economic attractiveness of an offshore wind park and that an interconnection to several markets will impact the business case.

Most of these analyses deal with offshore grids from a macroscopic perspective. There is however a certain lack of understanding as of how the market actors, especially the investors in offshore wind parks and transmission systems, are affected by the choice of regulatory regime in an offshore grid. This understanding is of utmost importance when designing the regulatory regime in order to ensure adequate investment incentives for wind parks and transmission capacity. A step towards this understanding was taken in an earlier study by the authors (Schröder and Kitzing, 2012) and is further elaborated in this paper. We approach the research gap with a real-options approach: we investigate an offshore wind park in an offshore grid under different regulatory regimes and support scheme constellations, and determine the option value of operational flexibility for additional interconnections. With the further development and extension of the quantitative model, we now address the economic impact of different regulatory regimes on the investors and operators of wind parks as well as transmission systems.

Our model shows that there can be both positive and negative effects on the business case of the offshore wind park operator. We argue that the specific effects should be considered when choosing the regulatory regime and designing the support scheme in the offshore grid, in order to maintain the effective and efficient development of offshore wind in Europe.

The remainder of the paper is structured as follows: after an explanation of the investigated cases in section 2, we address the applied method in section 3. Then we turn to the quantitative results and their discussion (sections 4 and 5). The paper concludes with qualitative conclusions and considerations on policy options (section 6).

2 Possible regulatory solutions and pricing schemes in offshore grids

We investigate a fictive offshore wind park in an offshore grid, connected to between one to four archetypical European markets, with regard to different regulatory regimes and support scheme constellations. We consider two different support schemes: Feed-in tariffs and price premium mechanisms. Under Feed-in tariffs (FIT), a fixed remuneration per MWh is guaranteed and paid to the wind park operator for a fixed number of years (or generation hours). Selling the generation on power markets and correction of forecast errors is typically administered by the TSO, leaving the wind park operator with only limited market risk. Price premium mechanisms, or Feed-in premiums (FIP), are typically fixed add-on payments to the market price. The wind park operator has to sell the generated electricity on power markets and is exposed to both market price risk and forecast errors.

Since wind farm operators under feed-in tariffs are not exposed to significant market risk, market pricing rules do not play a decisive role in the investment decision. In the case of feed-in premium mechanisms, operators are exposed to market price signals and market pricing rules for the offshore grid become decisive. In extension to our previous analysis, we distinguish three fundamentally different regulatory regimes in terms of market access and spot market pricing rules:

1) **‘Home’ country**: The wind park in the offshore area is assigned to one ‘home’ country and has only secondary access to the other connected markets;
2) **‘Primary access’:** the offshore area is flexibly integrated into any of the neighbouring markets, so that the wind park operator has access to the respective maximum price;
3) **‘Offshore hub’**: the offshore area forms its own market price area and thus the wind park operator is subject to specific nodal pricing.

The first case depicts a situation of limited cross-country coordination, when for example the participating countries would like to benefit from the price-equalising effects of additional interconnection capacity between the markets, but are not cooperating at a higher level, such as regarding the support scheme. Then, an offshore wind farm would be assigned one ‘home’ country into which it would primarily sell the power and receive the support. In case the market price in another country happens to be higher than the one of the ‘home’ country plus support, the wind park may choose to sell the power in that market. This is socio-economically not an optimal utilisation of the interconnection capacity as the price-equalising effect will be distorted by the support level. This effect is reflected by lower congestion rents collected by the transmission system operators (TSO).

The second and the third cases do allow an optimal utilisation of the interconnection capacity, as we here assume a support scheme specific for the offshore area, i.e. the wind park would receive a price premium no matter in which market the power is sold. The two cases differ in the pricing rules: In the second case, the production from the wind park is integrated in one of the neighbouring markets, and will receive the price of the respective market. The choice into which market to sell is left to the wind park operator. He will directly sell the produced power into any of the markets via a specifically reserved capacity in the interconnectors. The rest of the interconnectors are dispatched in implicit auctions. We refer to this case as the ‘primary access’ case.

In the third case, the offshore grid becomes an integral part of a larger market area with different price nodes (such as the Nord pool area), with implicit auctions on the entire interconnection capacities, and a separate price that may form in the offshore grid node in case of congestions. The offshore wind park operator will always be subject to the price that forms in the offshore node, which in many cases is equal to the lowest or a medium price of the neighbouring markets (Schröder and Sundahl, 2011). We refer to this case as the ‘offshore hub’ case with nodal pricing.

The number of countries (and therewith markets) that are participating in the offshore hub with respective interconnector capacities are decisive for the attractiveness of investment in an offshore wind park. In the benchmark case, only a connection to one market is assumed. We investigate the economic impact on the business cases for the wind park and interconnection cables induced by additional connections to other markets under all three regulatory regimes. Figure 1 illustrates the different fictive connection situations distinguished in this paper: the benchmark case is a 600 MW offshore wind park connected to country A by a cable with the same capacity. This connection can be complemented by additional 600 MW interconnectors to the neighbouring countries B, C and D.

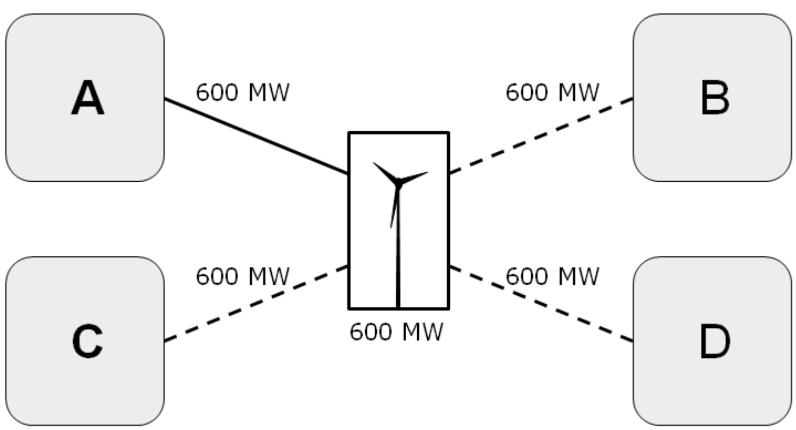

Figure 1: Overview of connection options in the considered cases

In addition to the connections, two other parameters are worth investigating: failure risk of any of the connections might impact the business cases significantly, depending on the regulatory set-up. Especially relevant for the stochastic analysis and therewith the option value is the strength of price correlation between the investigated markets.

The above considerations lead us to the following cases we investigate during the remainder of the paper:

	Benchmark	**'Home' country case**	**Primary access case**	**Offshore hub case**	**Special cases**
Geographical area	Country A	Countries A + B, C, D			
Renewable Support	Feed-in tariff Feed in Premium	Feed-in Premium (in Country A)	Feed-in Premium (joint scheme)		
Applicable price areas	Country A	Country A, and very high prices in countries B to D	Highest prices of countries A to D	Offshore price node (typically median of prices in countries A to D)	
Special events	-				Line Failures High market correlations

Table 1: Overview of the analysed cases and their main distinguishing characteristics

In order to capture the uncertainties related to the exposure of the offshore wind park to market price fluctuations under a price premium scheme and to integrate line failures into our considerations, a stochastic model is applied for the quantitative analysis. We use a real-options approach where any additional value related to the operational flexibility of being connected to other countries is regarded as the option value of the additional interconnection.

3 Method

Market prices of the different markets are modelled as stochastic mean reverting Wiener processes, following well-established methods. Stochastic line failures are reflected by the authors' own approach, inspired by previous modelling of jump processes in commodity prices (see e.g. Hambly et al., 2009). We then compare the mean expected value of a wind park and its standard deviation in the different cases of regulatory regimes and country-connections to the benchmark case. This benchmark case is a wind park connected to one country only. At the same time, changes in congestion rents obtained by the involved TSOs for the different cases are analysed.

3.1 A stochastic model for the value of a wind park under price uncertainty

We use a well-established and often used approach (based on Dixit and Pindyck, 1994) to develop a stochastic model of the spot electricity price in four countries, where electricity prices are a stochastic process following a Brownian motion. The stochastic behaviour of prices, including drift and volatility, are exogenously given to the model. It has often been shown that most commodities in general and electricity prices specifically show characteristics of mean reversion and seasonal patterns (Lucia and Schwartz, 2002). Considering the nature of the analysis, which is a comparison of different cases with the same underlying market price processes, we include mean reversion in the model, as it will indeed affect the results, especially because the cases are sensitive to small price differences between the countries. Seasonal patterns however are not expected to modify the comparative attractiveness of the cases significantly, as they would apply similarly to all countries. Therefore, seasonal patterns are not included in the model. The price processes are modelled as plain mean reverting Wiener processes after Dixit and Pindyck (1994). The stochastic change of price in each time step dx is expressed with the mean reverting stochastic process:

$$dx = \kappa * (x^{*} - x)\, dt + \sigma\, dW_t \qquad (1)$$

Where:

- W_t is a Wiener process with independent increments at $W_t - W_s \sim N(0; t-s),\ for\ 0 \leq s < t$
- κ is the mean reversion factor of the market (exogenously given)
- σ is the standard deviation of the market (exogenously given)
- x^{*} is the 'normal' level of the price x_t, to which it tends to revert, i.e. the long-run marginal cost of production in an electricity system

The processes are Markovian, meaning that the distribution of future prices is only dependent on the present price and not the past history of prices, i.e. it follows fundamental signals. In this framework, the price x_t in each time step can be calculated from the previous price plus the expected change dx from a stochastic process:

$$x_t = x_{t-1} + dx \tag{2}$$

For the simulation, we use the related first-order autoregressive process in discrete time (see Dixit and Pindyck, 1994, p. 76):

$$x_t = \overline{x_t} * (1 - e^{-\kappa}) + (e^{-\kappa} - 1) * x_{t-1} + \varepsilon_t + x_{t-1} \tag{3}$$

Where:

- $\overline{x_t}$ is the 'normal' level of x_t, to which it tends to revert. $\overline{x_t}$ includes a drift in the process and is therewith also dependent on t
- ε_t is a normally distributed random variable with mean of zero and variance of

$$\sigma_\varepsilon^2 = \frac{\sigma^2}{2*\kappa} * (1 - e^{-2\kappa}) \tag{4}$$

Having the stochastic price processes for all four countries in place, we then model the hourly expected future cashflows of the wind park mainly dependent on revenues from sales into the different spot market based on the restrictions given by the different cases we investigate. Next, future cashflows are aggregated over the analysis period, i.e. the lifetime of the wind project, and a traditional discounted cashflow calculation is undertaken to determine the project value, here expressed as the internal rate of return in each scenario and each realisation of the stochastic price process (Brealey and Myers, 2002).

$$NPV = \sum_{t=0}^{T} \frac{CF_t}{(1 + IRR)^t} = 0 \tag{5}$$

Where:

- IRR is the internal rate of return in each realisation of the price processes in each scenario
- NPV is the net present value of the wind park
- CF_t is net cashflow in period t (net of positive and negative cashflows)

t is the time period of the Cashflow

T is Number of periods, i.e. the lifetime of the wind park

Mean and standard deviation of the net present value of the project for the different cases are determined by a Monte Carlo simulation (N=1,000) capturing different realisations of the price processes.

3.2 A model for stochastic line failures

Stochastic line failures are added as an optional choice to the model. We model the probability of occurrence of a line failure with a Poisson distribution $P(\lambda)$, which reflects the nature of the failures much better than e.g. a normal distribution. This modelling approach is comparable to modelling of jump processes in commodity prices (see for example Hambly et al., 2009). The probability of duration of the line failure is modelled as a normal distribution $N(0; d)$. We also add an exponential recovery process for the available capacity y_t when ramping up after the line failure, approaching exponentially to the maximum available capacity $\hat{y}$, the nominal capacity of the interconnection capacity between the wind park and the respective country.

$$y_t = \hat{y} - \hat{y} * i_{(t,\varepsilon)} - \left(\hat{y} * j_{(t,\theta)} + (e^{-\kappa} - 1) * y_{t-1} + y_{t-1}\right) \tag{6}$$

Where:

y_t is the value of available interconnection capacity, being restricted to $0 \leq y_t \leq \hat{y}$

$\hat{y}$ is the nominal capacity, i.e. the maximum available interconnection capacity between the wind park and the respective country. It also serves here as the jump size in the Poisson process, meaning that the failure is expected to affect 100% of the capacity

κ is the recovery rate of the exponential process towards the maximum available capacity $\hat{y}$

$i_{(t,\varepsilon)}$ is the variable that activates the line failure, with

$$i_{(t,\varepsilon)} = \begin{cases} 1, & \varepsilon_t > 0 \\ 0, & \varepsilon_t = 0 \end{cases}$$

ε_t is a Poisson distributed random variable with mean of λ , $\varepsilon_t \sim Pois(\lambda)$

λ is reflecting the expected number of line failures per year

$j_{(t,\theta)}$ is the variable that activates the recovery process after an outage, with

$$j_{(t,\theta)} = \begin{cases} 1, & t = t_p + \theta_t \\ 0, & t \neq t_p + \theta_t \end{cases}$$

t_p is the maximum value of t, in which a line failure last occurred, with $t_p = t \;\; at \; \varepsilon_t > 0$

θ_t is a normally distributed random variable with mean of zero and standard deviation of d, $\theta_t \sim N(0; d)$

d is reflecting the expected number of hours the outage lasts

3.3 Assumptions

As described in a previous section, we investigate a fictive case with four archetypical markets and a typically sized offshore wind farm of 600 MW. We assume the addition of 600 MW interconnectors to other countries as main distinction criterion between the cases. This has a crucial effect on results: the capacity of the wind farm is such that typically all its power can be sold into one market. Other capacity combinations, especially combined with different electricity price characteristics in the neighbouring countries, would most likely have a considerable impact on the results. This issue is dealt with in a sensitivity calculation, where we vary the connection capacity.

The electricity price processes for all four countries (see section 3.1) are assumed to share the same fictive stochastic parameters. The starting mean value is assumed at 50 Euro/MWh with a drift of +1 Euro/MWh towards the end of each year. The volatility is expressed as a standard deviation before mean reversion at 1.5 Euro/MWh, while the mean reversion coefficient κ is set at 0.01. Markets are non-correlated, except for one special case, where the effect of high market correlation is analysed by assuming a correlation of 0.9 of market A with B, C and D.

Regarding the stochastic line failures (see section 3.2) we assume that on average three annual interruptions occur with a normally-distributed duration with expected 50 hours per outage. The line failures are assumed to occur with a Poisson-distributed frequency with a λ of 3. The spike mean reversion parameter κ, reflecting the speed of return to nominal capacity after a line outage, is set at 0.05. The average failure duration of 150 hours per year corresponds to 1.7% outage per year, which is regarded to lie in a realistic range (Lindén et al., 2010 and Waterworth et al., 1998).

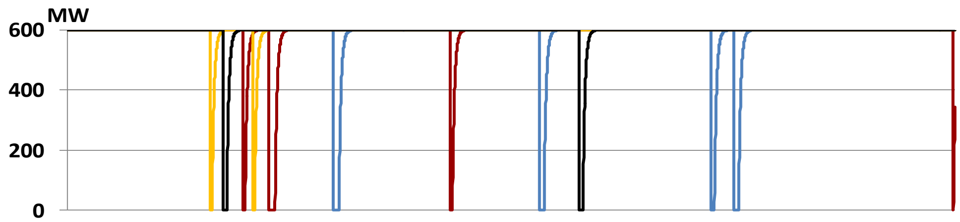

Figure 2: Exemplary outage results for the four interconnectors over a full year

The wind time series is based on measured wind data at the FINO1 platform in the South-Western part of the German sector of the North Sea for the year 2006. It has been processed into an hourly production pattern accordingly to Nørgaard et al. (2004) and approximately adjusted for wake effects. The 600 MW offshore wind park is assumed to have a lifetime of 25 years, about 4,475 full load hours, investment cost of 2.45 million Euro/MW and operational expenditure of 0.07 million Euro/MW/year. These assumptions on the offshore wind park are based on ENS (2010). Apart from the rather high value for full load hours derived from wind time series, these numbers are in line with Deloitte (2011) and assessed to be realistic for the nearest years to come.

4 Quantitative results

The quantitative results we obtain and discuss further are different for wind park and transmission system operators. For the offshore wind park, the Internal Rate of Return (IRR) represents the value of the wind park and therewith the investment incentive. We consider the expected mean IRR and the standard deviation of the IRR from the Monte Carlo simulations. For the TSO, the income from the interconnection operations forms the basis to evaluate the interconnections and therewith the investment incentive in additional cables. The TSO collects the income as congestion revenues, also called congestion rents, which are income from price differences on the participating spot markets and the implicit energy flows between them. We consider the expected annual mean congestion revenues as well as their standard deviation derived in the same Monte Carlo simulations as for the wind park.

4.1 One country – benchmark case

In the benchmark case, the offshore wind park is only connected to one country and is thus fully integrated into that one market. In case the wind park receives a guaranteed price in form of a feed-in tariff, the wind park is not exposed to the volatility of that market and all Monte Carlo simulations result in the same IRR for the wind park (see Figure 3, left). In case of a fixed price premium paid out in addition to the market price, the wind park is exposed to the underlying volatility and the Monte Carlo simulations yield a normally distributed outcome of the IRR (Figure 3, right). We have designed the cases in such way that the expected mean IRRs for feed-in tariffs and premiums are the same in the benchmark case, namely 9.8%. The difference in attractiveness of the two cases lies in the different standard deviation – The higher the standard deviation, the higher the riskiness of the project. The Feed-in premium case yields in a standard deviation of 0.4%-points. This result forms the basis of comparison for our further analyses.

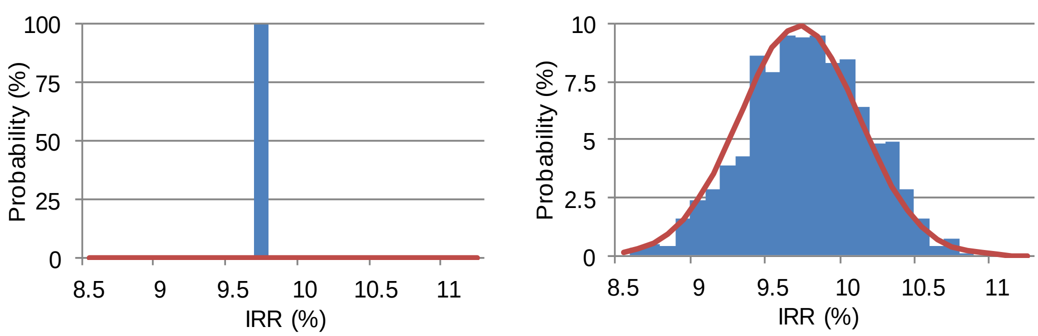

Figure 3: Wind park IRR for feed-in tariff support (left) and price premium support (right)

The congestion revenues for the TSO are assumed to be zero in the benchmark case, meaning that we only consider and compare the additional income generated by the new cross-border connections in the offshore hub in the two to four country cases.

4.2 Home country case

In this case, the offshore wind farm has primary access to its home country – where it is remunerated at the market price plus a price premium – and secondary access to the other countries, where it is only remunerated at the respective market prices. Quantitative results are depicted in Figure 4 and show that the average IRR increases with the number of markets while the standard deviation decreases. The average IRR can be increased from 9.8% under the connection to one country up to 10.3% under the connection to four countries. The marginal benefit of each additional connection is decreasing. In addition to an increase in IRR, the standard deviation, which we use as indication for riskiness of the investment, decreases when adding more countries, in our simulations from 0.4%-points in the benchmark case to 0.32%-points in the four country case.

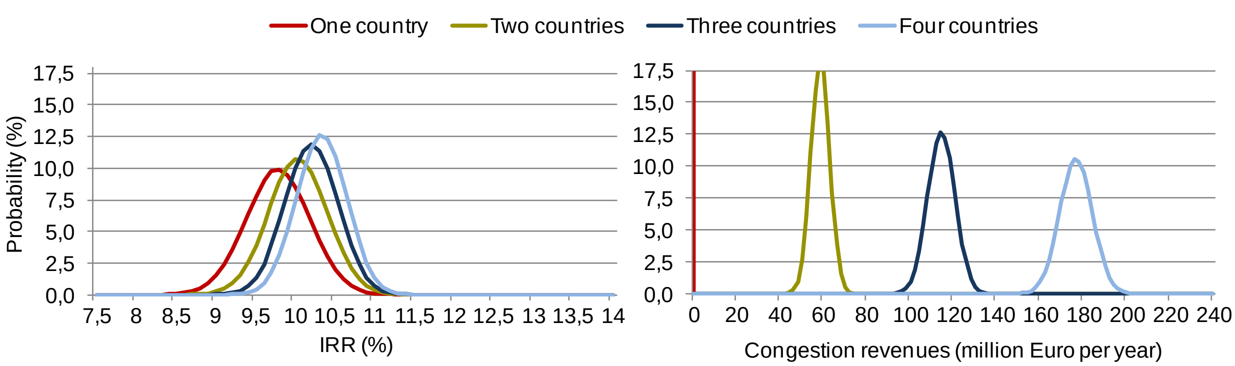

Figure 4: Wind farm IRR (left) and TSO congestion rents (right) in the home country case

Considering congestion rents (Figure 4, right), they increase with each additional connection and exceed the level achieved under primary market access by approximately 10 million Euro. The volatility, expressed as standard deviation of the congestion rents, increases from 4.3 to 6.3 million Euro when changing from two to three connected countries. Continuing to four connected countries, a further increase to 7.5 million Euro can be observed.

4.3 Primary market access

In cases where primary access is chosen as regulatory framework, the wind park operator has full benefit from the additional connections, whereas the TSO can only use the residual capacity. The wind park can choose into which market it sells the electricity and can therewith achieve a higher income from choosing the highest price at any point in time – the more countries are connected, the higher the value of the wind park (see Figure 5, left).

As already shown in Schröder and Kitzing (2012), the option to be connected to different countries increases the value of the wind park significantly. The value of the wind park is here expressed as mean expected IRR and increases with up to 33% in the four-country case compared to the benchmark case (up from 9.8% to 13.0%) when assuming a constant feed-in premium. In addition to an increase in IRR, the standard deviation decreases more than in the home country case, in our simulations with up to 42% (down from 0.4% to 0.24%). This is due to the fact that the wind park is less exposed to the volatility of market prices in one country as it has the option to switch sales to any other country whenever a low price period occurs. We conclude that the wind park operator will in this regulatory regime benefit from any additional connections: he can expect a higher IRR and at the same time a risk reducing effect. The risk-reducing effect is increased when taking line failures into account, whereas the expected project value and the risk reducing effect is decreased when considering correlation between the market prices of the participating markets. In our example, the IRR decreased by 0.6%-points when considering a two-variate correlation of all countries with country A.

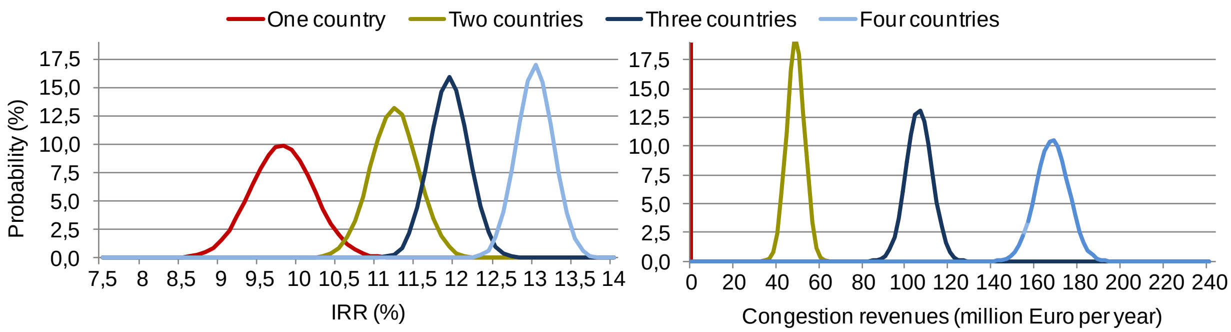

Figure 5: Wind farm IRR (left) and TSO congestion rents (right) in the primary access case

For all interconnector capacity that is not utilised by the wind park operator, the TSO collects congestion revenues from price differences in the adjacent markets. Figure 5 shows the expected amounts and probability distributions for this income. Compared to the two-country case, the expected income increases with 119% in our simulations (+58 million Euro) when adding one more country, and yet another 61 million Euro to 167 million Euro with addition of the fourth country. This is due to the fact that in the chosen set-up, single interconnectors have the same capacities and an even number assures a better asset utilisation than an odd number of lines. As an example, in periods without wind generation, one interconnector can export while another one imports. In a three-country case, this leaves the third interconnector idle. In a four-country case, the constellation is symmetrical again. Regarding volatilities, it becomes apparent from the simulations that – contrarily to the wind park operator – the TSO faces higher volatility in income when more countries are connected to the offshore hub. This is the case for markets with no or low correlation, since the additional volatility of each market adds to the overall fluctuation in price differences, which is the major income source for congestion rents. In a situation where the adjacent markets are highly correlated, both the level of income and the standard deviation decrease significantly.

4.4 Offshore price hub

In cases where the regulatory framework constitutes an offshore hub which forms its own price area, the wind park operator will not be able to choose on which market to sell his production. The offshore wind park will be subject to the price that forms in the offshore hub. This price is dependent on the price levels and price differences in the neighbouring markets as well as the overall available interconnection capacity. The flow in the connections from the wind park and the different countries is determined in implicit auctions. In almost all realistic situations, there will be at least one connection from the wind park to a country which is not congested, and the offshore hub price will thus equal the price of that market. This will typically not be the highest available price (Schröder and Sundahl, 2011). Therefore, the wind park will be valued at a lower level than in the case of primary access.

As was discussed in Schröder and Kitzing (2012), the model results reveal an interesting characteristic of how this regulatory framework impacts the wind park under the assumption of identical interconnector capacities. When two countries are connected to the offshore price hub, the hub will always form a price that corresponds to the lower of the two prices; therefore the impact is very significant with a decrease of ca. 15% (from 9.8% to 8.4%). In a case of three countries, the offshore price hub will form a price that corresponds to the median of all three prices. Some of the impact of the two-country case is mitigated. In a four country case, however a price will form that corresponds to the second lowest of the four market prices. In terms of riskiness of the project, i.e. standard deviation, the different country-cases show similar distributions as with primary access – a higher number of countries coincides with a lower standard deviation. The resulting IRR probability distributions are illustrated in Figure 6. The differences of the cases are much less pronounced if there is significant price correlation between the markets of the countries especially when including periods of equal prices.

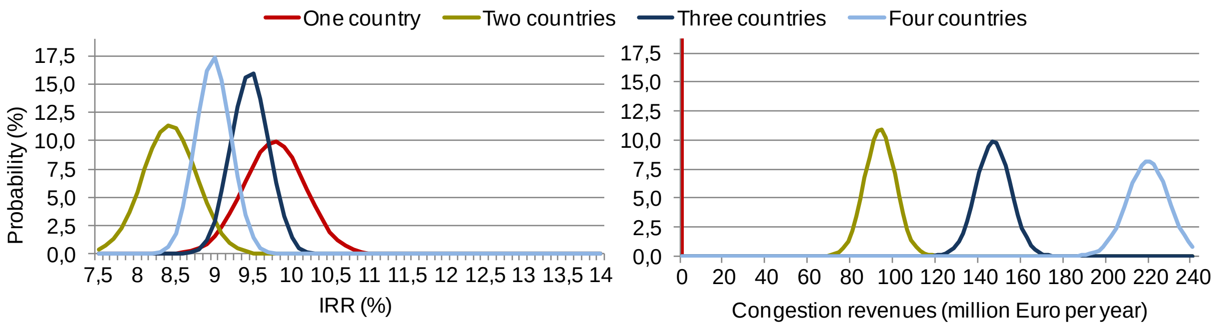

Figure 6: Wind farm IRR (left) and TSO congestion rents (right) in the offshore hub case

In the case of nodal pricing in an offshore hub, the TSO has access to the full interconnection capacity as the production and energy flows from the wind park is integrated in the overall market. Therefore, the TSO is able to collect more congestion revenues – the increase is in fact the same amount of revenues that the wind park operator loses in the offshore hub regime compared to primary access. The annual revenues lie in our simulations for each country-constellation 45-52 million Euros higher than in the primary access case.

It can be noted that the two-country case, which is the least attractive for the wind park operator is not the best case for the TSO, as the TSO's revenues increase with addition of more countries simply because more energy flow becomes possible. Also, the connection to a fourth country is not beneficial for the wind park operator, where it is for the TSO. In these cases, opposing interests of wind park operator and TSO could hamper the (further) construction of an offshore hub.

4.5 Special case: line failures

Line failures are a special case for this analysis, as the loss caused by line outages is a real reduction in energy flows between countries. Here again, it is a question of the regulatory framework in who is exposed to a potential loss from line failures – the wind park operator or the TSO. If the wind park operator is not compensated for line failures of the offshore cables, he bears risk of income loss from not being able to sell the power he produces. Figure 7 shows this situation for connection to one country on the left. If the wind park is connected to additional countries (each having similar risk of line failure) and has access to any of the other markets, then the wind park is less exposed to income loss the more countries are added, because it becomes less probable that all lines fail at the same time. Figure 7 shows that the income risk is nearly fully mitigated by four connections. This finding is in line with Macharey et al. (2012), who analyse possible interconnections between single German offshore wind clusters and conclude that meshed offshore structures can, even within one price zone, have a considerably risk-reducing effect and be profitable.

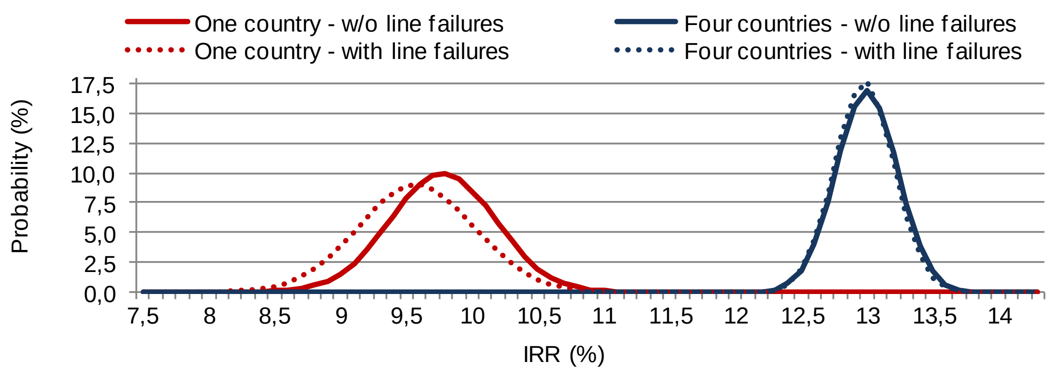

Figure 7: IRR probability distribution changes for the wind park considering line failures

This result can be of significant impact for the future valuation of wind parks in offshore hubs, especially in a regulatory regime with offshore hub pricing – the risk reducing effect on line failures might mitigate some of the disincentives for offshore wind park operators in the construction of an offshore hub. However, in a regulatory regime where wind park operators are fully or partly compensated for line outages, there will be no measurable or only limited impact on the wind park value. Here, the income for the TSO will, in addition to the losses from foregone congestion revenues, also be affected from the compensation payments for the wind park operator.

4.6 Comparison of all cases and sensitivity analysis

The overall comparison of all cases as illustrated in Figure 8 displays that wind park investors and the TSO have opposing preferences in regards to the regulatory regime. The TSO benefits clearly from a nodal pricing system in the offshore hub (all 'offshore hub' cases (yellow triangles) have the highest mean congestion revenues), whereas the wind park operator would prefer a regime with primary market access (green squares). Line failures have a much lower impact on cases than a high market price correlation (both special cases are connected to their respective reference cases by lines).

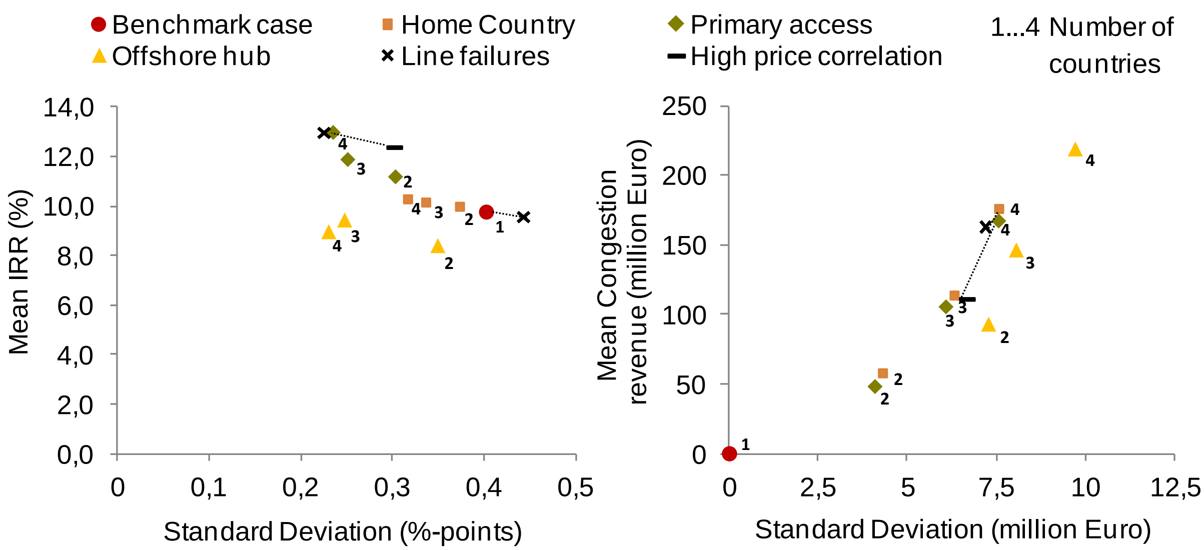

Figure 8: Overview of all case results for the offshore wind park (left) and the TSO (right)

The difference between primary access and nodal pricing is least pronounced for the three-country case: here, the primary access and nodal pricing cases differ only by 41 million Euro on average. The reason is a comparatively good case for the wind park under nodal pricing, which is at the expense of congestion rent income. This illustrates that option values between several cases are highly dependent on the underlying assumptions.

A sensitivity analysis for changed line capacities under nodal pricing shows that the wind farm's IRR standard deviation is only affected marginally, whereas the average return increases especially with the upgrade to 1,200 MW (Figure 9, left). This is due to the fact that, starting with the benchmark value of 600 MW for all cables, the connection to one country has been increased in steps of 200 MW until 1,200 MW. Reaching 1,200 MW, the interconnection corresponds to two other interconnectors leading to a new price formation constellation, which explains the major difference to a capacity of 1,000 MW. Regarding the congestion rents (Figure 9, right), the result fits with the expectation that additional interconnection yields decreasing marginal benefits.

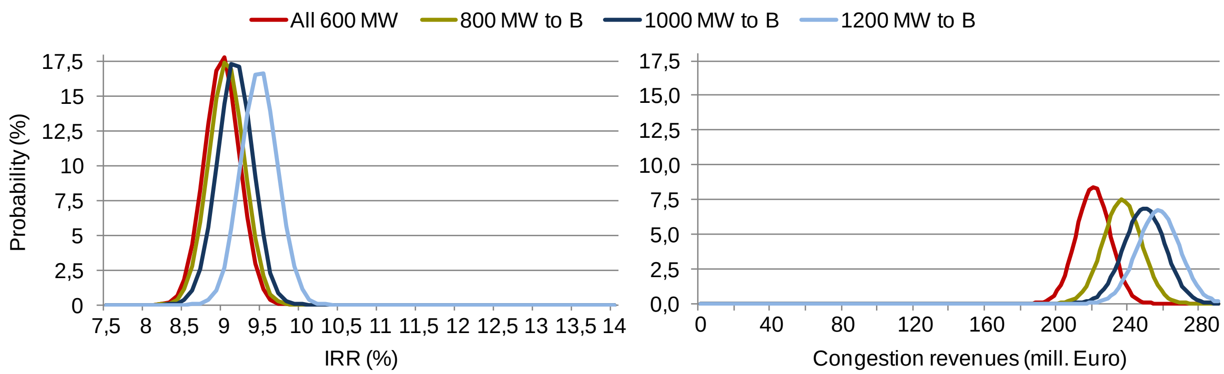

Figure 9: Wind farm IRR (left) and TSO congestion rents (right) for changed line capacities

5 Analysis and discussion

The investigated cases do not represent real conditions in terms of markets or technical options, but they carry some pure and archetypical characteristics of conditions for potential offshore grids in the European offshore territory. Therewith, they can serve as basis for the main points we wish to highlight. The results from the simulations show that the choice of regulatory regime has a decisive impact on the value of a wind park investment as well as for the income for transmission system operators. The impact can be both positive and negative for the different actors. Overall, we observe that the choice of regulatory regime in comparable cases, i.e. the primary access and the offshore hub case (with the same structure of RES support), has a re-allocative effect of benefits between the actors rather than creation of additional benefits. As long as connection capacities and market prices do not change between the cases, the aggregated benefits including the sale of wind power production and price differences between markets are the same. In case of primary access, more of the benefits are allocated to the wind park operators, and in the offshore hub with nodal pricing, more income is allocated to the TSO. Both regimes are feasible – it is a policy choice which regime should be implemented. In this regard, some considerations should be made.

First, offshore wind park are and will for the near future be dependent on financial support by specific instruments such as Feed-in tariffs of Feed-in premiums. If a regulatory regime is chosen that exposes the investor in offshore wind parks to market risk and at the same time to nodal pricing in the offshore hub, there is a significant risk of lower IRR when additional countries are added to the offshore hub. The attractiveness of investment is consequently decreased. In order to trigger an adequate amount of investment, the level of support needs to be increased. The higher support level could be paid from the additional congestion rents that the TSO incurs. By contrast, if a primary access regime is established, the wind park operator could benefit from significant windfall profits when additional countries connect into the offshore grid. To avoid socio-economically overly expensive support mechanisms, the level of support should be corrected downwards for each new country in the offshore grid.

Second, the level of cooperation between the countries needs to be taken into consideration. It will not always be possible to create an offshore hub with nodal pricing due to the high level of coordination. If one country has a well-established national Feed-in tariff system, only a strong ‘home’ country affiliation seems to be practically possible. However, an offshore hub regime with nodal pricing could especially become interesting for internationally coordinated support schemes in the future to ensure neutrality between the neighbouring countries (see Schröder et al., 2011).

In addition, the sensitivity analysis on interconnector capacities to different markets shows that quantitative results exhibit remarkable differences if the connection to one country reaches an integer multiple capacity of the capacities towards other countries. It should be emphasised that this also depends on the assumed generation time series and capacities.

We have limited our analysis to spot markets. In reality, balancing markets and their prices might be a very decisive factor in choosing on which market to sell. The cases and countries investigated do not represent a realistic market environment. Before drawing conclusions on real-world cases, the model should be calibrated to real market characteristics; especially the level and volatility of the markets are decisive. This, however, could first be applied for a real-world case where the interconnector capacities and market price characteristics are known and where the offshore node's generation is handled differently than national onshore generation. A main simplification is that we look at real option values for the whole lifetime of the project. This supports transparency, but would probably not apply in real-world cases: additional interconnectors are first decided upon after the offshore wind farm comes into operation. So, for more realistic cases, a sensitivity analysis on additional interconnectors only after a certain number of years would provide valuable insights.

6 Conclusions

This paper presents an analysis on the economic effects of different regulatory regimes on offshore wind parks and transmission system operators in an offshore grid. Stochastic price processes and line failures are modelled for four spot markets. An offshore wind farm as part of a meshed offshore grid is connected to between one and four of these markets, experiencing different option values of additional interconnectors.

The analysis reveals two major insights: First, we have shown that the regulatory regime, including market access and pricing rules, has a significant impact on the valuation of assets in an offshore hub, both wind parks and interconnection capacity. The choice of regulatory regime can have both positive and negative impact on the actors. In our (fictive) case with connections to four similar archetypical power markets, the IRR for an investment in a wind park increases with up to 33% if the wind park has primary access to all markets. Contrarily, establishing an offshore hub with nodal pricing can have a negative impact on the IRR of up to 15%. So, the incorporation into an offshore grid is far from neutral for an offshore wind park. This leads to the question of how to compensate for possible losses or gains under the suggested regulatory mechanisms. Our results show this may need to be handled on an interconnector-by-interconnector basis: while the connection to a third country is beneficial for the offshore wind park under nodal pricing, the connection to a fourth country is negative.

Second, the incentives for the different market actors in relation to additional connections are very different and in some cases even contrary. This is particularly visible for the offshore price hub, where the wind farm's profit increases or decreases depending on the number of the connection to be made. It can contrarily still be a good business case to add a cable that is negative from the wind farm's point of view. Thus, the market actors such as transmission system operators and wind farm operators may take very different positions towards establishing new connections at different stages in the development of meshed offshore grids – which may hamper the construction of new lines that are beneficial from a socio-economic perspective. Both effects should be considered in future valuations of wind parks and offshore hubs as well as in the design of the regulatory regime for the offshore grid and the level of support for the wind park. Only then, an effective and efficient development of offshore wind in Europe can be achieved.

The sensitivity analyses that we have undertaken regarding different interconnection capacities shows that minor upgrades for single interconnectors improve the wind farm's income only marginally. A larger improvement is reached when a capacity corresponding to existing capacities (600 MW in the example) is added. As expected, the marginal benefit of additional capacity decreases from a TSO point of view.

Our results can be used when considering how to design a cross-border offshore hub, such as envisaged in the Kriegers Flak area, to make an informed decision. In order to balance incentives for investment and socio-economic efficiency, the support level, i.e. in our case the fixed price premium, could be adjusted according to changes in wind park value and riskiness.

The attractiveness of offshore grids for different market actors depends heavily on the choice of regulatory regime, including market access, pricing rules and support. Certain constellations of regulatory regimes create barriers that may hamper the development of offshore grids due to diverging incentives. If meshed offshore grids are to be built due to their socio-economic benefits, the effects described in this study should be taken into consideration when making regulatory choices.

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