Økonomiske analyser af havvindprojekter – herunder en detaljeret analyse af Energiø Bornholm

Report developed by the Boston Consulting Group (BCG)
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BCG

Energistyrelsen

Executive Summary

Background: The Danish Energy Agency (DEA) has extensive experience conducting socioeconomic analyses of offshore wind projects. It now seeks a deeper understanding of how developers build their business cases and how this affects the potential level of state support needed to make project realizations likely. Boston Consulting Group (BCG) has therefore conducted a study with a two-fold purpose:

- Provide DEA with a replicable methodology for calculating developer hurdle rates, business cases, and potential support budget cap for offshore wind projects.
- Apply the methodology for the specific case of Energiø Bornholm (EØB), with the purpose of estimating the subsidy amount that makes realizing the project likely.

Content: The first two chapters describe a generic methodology for determining hurdle rates and calculating the corresponding business case and support budget cap for an offshore wind project. This framework is supported by an appendix outlining the step-by-step process for deriving the required input parameters. The third chapter applies this methodology to EØB, estimating the support budget cap needed to make project realization likely. The support schemes in scope are capability-based contract for difference (cCfD) and feed-in premium (FIP).

Introduction: Offshore wind developers assess project viability using discounted cash flow models, where the hurdle rate represents the minimum unlevered internal rate of return (IRR) required for a project to be viable. Risks related to the project are reflected either through the hurdle rate (e.g., market, technology, and commercial risks), as contingencies in the business case (e.g., supplier, construction, and financial risks), or through qualitative assessments (e.g., tender criteria risks and project size).

Hurdle rate methodology: To estimate the hurdle rate developers are likely to apply for a specific offshore wind project, a bottom-up approach based on different developer archetypes is applied. The hurdle rate comprises the weighted average cost of capital, project-specific risk premiums, and the margin that makes the project financially acceptable. The choice of state support scheme will impact the hurdle rate through the project-specific commercial risk premium: a 20-year cCfD entails a relatively low risk premium (0-1.0 pp.), whereas a FIP scheme implies higher risk (1.5-2.0 pp.), and full merchant power price exposure carries the highest risk premium (2.0-3.0 pp.). While the approach presented is comprehensive, a pragmatic approach is recommended when determining hurdle rates of future projects, using the values established through this methodology as a baseline and validating them with the market.

Business case and support budget cap methodology: After determining the hurdle rates, business case- and support budget cap analyses can be performed. The first step is to construct a discounted cash flow model to calculate the unsubsidized baseline business case from a developer's perspective. The necessary level of support is then derived such that the project's IRR equals the required hurdle rate. For the cCfD and FIP schemes, this is calculated as the total state payments when the strike price (cCfD) or premium (FIP) is set to the level that achieves this target return. Once the support requirements have been calculated, sensitivity analyses are used to form scenarios to calculate the support budget cap, including a buffer between the support requirements and the budget cap.

Introduction to EØB: The methodology outlined above is applied on EØB; a planned 3 GW hybrid offshore wind project that will connect Denmark and Germany through new interconnectors to Bornholm. Energinet will build a 1.2 GW link to Zealand (DK2), while 50Hertz will construct a 2 GW link to Germany. The investment cost for the interconnector to DK2 may be covered partly by the offshore wind developer through annual payments (base

case), while 50Hertz will cover the costs for the German interconnector. The project, located in a new DK3 price zone, is expected to deliver first power in 2034 and reach full operation by 2037.

EØB risk factors: Beyond the risks common to all offshore wind projects, several additional risk factors are present for EØB. The large scale (3 GW awarded to one developer / consortium of developers) represents an unprecedented investment that could limit developer participation. Its dependence on two interconnectors introduces exposure to potential curtailment or grid downtime, while high uncertainty around future balancing costs in the new DK3 price zone adds further risk. In addition, uncertain grid access during the initial test phase before 2037 poses a risk to early revenues. Each factor is considered significant enough to deter bids if not addressed before the tender. They are therefore to be mitigated to an acceptable level in advance, and their current magnitude is not reflected in the calculated hurdle rate or business case.

EØB hurdle rates: Hurdle rates for EØB are estimated at 11.5% if having full merchant power price exposure, 8.5% under a cCfD, and 10.0% under an FIP. These values were validated through dialogue with developers, whose feedback confirmed that the selected ranges are within current market expectations for a project like EØB. These hurdle rates reflect the current negative market sentiment, characterized by greater risk aversion, delayed power demand, and a more selective market focus, with developers prioritizing value over volume.

EØB support requirements: The offshore wind market has not improved since the 2024 tender analysis performed by BCG in early 2025. Without state support, the project's IRR is estimated at –0.9%, far below the required 11.5% merchant hurdle rate, confirming that a subsidy mechanism is essential for viability. Under a cCfD, a strike price of 115 EUR/MWh would be required to meet the 8.5% hurdle rate, corresponding to an estimated 139 BnDKK in total support (base case). Under an FIP scheme, developers would require +92 EUR/MWh on top of the capture price, translating to 172 BnDKK in total support. These estimates are non-discounted total support in real 2025 terms, assuming payout over the full 20-year scheme duration.

EØB support budget cap: Sensitivity analyses are used for key input parameters to define three scenarios to determine the support budget cap; Low-, Mid-, and High-support. The Mid-support case is selected as the basis for the proposed support budget cap, providing a buffer to the base case support requirements based on slightly more conservative CapEx-, power price-, and balancing cost assumptions. To make the realization of the EØB project likely, the support budget cap under a cCfD is estimated at 160 BnDKK if paid out over 20 years (Mid). In an optimistic case where the industry recovers, the budget cap would be 97 BnDKK (Low), whereas it would be 221 BnDKK in a more negative case (High). If assuming that the budget is paid out in less than 20 years in the Mid scenario, the budget cap can be lowered to 132 BnDKK (10 years), or even as low as 113 BnDKK in an extreme case where the budget is paid in full at the date of commissioning. The values presented assume corporate taxes are paid in full for the project, which is likely not the case due to tax optimization performed by developers. If assuming no taxes are paid from the project, the support budget cap under a cCfD is estimated to 132 BnDKK if paid out over 20 years (Mid).

EØB support budget cap reduction levers: It is outside the scope of this project to assess potential levers to decrease the required state support, and the corresponding budget cap. Nevertheless, it should be mentioned that there are measures that could be considered by the government to improve the business of developers and hence reduce subsidy requirements. Examples include full state financing for the interconnector to DK2 and earlier start of the support scheme. As an example, the sensitivity analysis shows that full state financing of the interconnector will lower the required support budget cap to approximately 142 BnDKK.

Introduction

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- Provide DEA with a replicable methodology for calculating developer hurdle rates, business cases, and potential support budget cap for offshore wind projects.
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The content of the report is structured in 4 chapters:

1. Methodology for determining hurdle rate: Outlines a standard approach that DEA can apply for estimating hurdle rates of offshore wind developers.
2. Methodology for determining support budget cap: Outlines a standard approach that DEA can apply to estimate the required support budget cap under any given subsidy scheme to increase the likelihood of realizing an offshore wind project.
3. Likely hurdle rate and support budget cap for EØB: Applies the methodology described in chapter (1.) and (2.) to estimate the hurdle rate and support budget cap required for making the realization of EØB likely.
4. Conclusion: Summarizes the key takeaways from the assessment.

In addition to the main chapters listed above, three appendices are provided:

- Appendix A: Describes the differences in support requirements when applying DEA's assumptions versus the assumptions applied by BCG in this report.
- Appendix B: Summarizes the most important takeaways from dialogue with developers during the project, complementing the insights incorporated in the main report.
- Appendix C: Outlines a step-by-step logic for obtaining the right input parameters and conducting analyses of support requirements for the DEA to leverage in future projects.

1 Methodology for determining hurdle rate

This chapter provides an overview of a systematic methodology for determining hurdle rates for an offshore wind project from a developer perspective. It is generally challenging to estimate hurdle rates of developers outside-in[1], and there is a risk of errors due to insufficient input data or inaccurate assumptions. Therefore, bottom-up estimations of hurdle rates should always be complemented by top-down adjustments through dialogue with the market.

> The hurdle rate can be defined as the minimum internal rate of return (IRR) that a developer requires for a project to be economically acceptable. This includes the cost of capital, any project-specific risk premiums, and the minimum margin the developer would add on top. This report focuses on the post-tax hurdle rate, which represents the return a developer requires from a project after taxes are paid.

This chapter starts with a description of the different options for financing offshore wind projects, and how different archetype developers have usually financed their projects in the past. The focus then shifts to a description of the methodology for determining the hurdle rate of developers, and finally how different support

[1] Refers to determining hurdle rates based on publicly available data on companies.

schemes impact hurdle rates. A capability-based contract for difference (cCfD) and a feed-in premium model (FIP) are in scope in this report.

1.1 Options for financing offshore wind projects

There is a broad spectrum of financing structures for offshore wind projects, each with varying degrees of complexity. While this report does not explore every financing model in detail, it focuses on providing a robust framework for determining hurdle rates from a developer's perspective. The two primary archetypes considered are balance sheet financing and project financing, and the optimal choice depends on each developer's capabilities, risk appetite, tax considerations, and strategic preferences.

In practice, financing structures often involve partnerships. Offshore wind developers frequently form joint ventures to combine complementary strengths, share risks, and access more competitive cost of capital. Some developers partner with institutional investors such as pension funds, sovereign wealth funds, or other financial institutions already before going into an auction. These act as passive equity holders, and can access low-cost capital, which can reduce the overall weighted average hurdle rate for the partnership, thereby enhancing bid competitiveness.

It should be noted that, across different financing structures, developers' hurdle rates tend to converge in magnitude. This is because increasing leverage in a project-financed structure raises the financial risk borne by equity investors, leading to a higher required return on equity. In practice, the higher equity risk premium often offsets the benefit of cheaper project debt, meaning that the overall weighted cost of capital remains broadly similar. Consequently, the choice of financing model is not critical when modeling an average developer. For completeness, this report includes views on both balance sheet- and project financing, and how different developers are likely to apply the two models.

Balance sheet financing
Under balance sheet financing, offshore wind developers fund the project on its corporate balance sheet, using corporate debt and equity. The company is liable for all financing, and terms will reflect the credit profile of the company, usually not directly linked to the individual project.

Balance sheet financing is typically used by large investment-grade companies with strong credit ratings that can access capital more cheaply at the corporate level than through individual project structures. Because financing is raised on the company's own balance sheet, this model does not depend on strict third-party requirements for project-level revenue certainty, as would be the case if leveraging project financing. Raising debt at the corporate level also allows risk to be spread across multiple projects, often resulting in a lower cost of debt than in project financing.

Several financing instruments can be applied for financing projects on corporate level. Bonds are common, with some developers issuing Green Bonds, that have distinct requirements for being applied for sustainable projects. These have the advantage of slightly lower costs for the developer, since investors are generally willing to accept lower returns on these bonds through a green premium[2]. Other financing instruments include loans and equity through retained earnings or new share issuance.

Project financing
Under project financing, offshore wind developers raise funding for the isolated project (usually special purpose vehicle), where the developer typically contributes with a certain share of equity (e.g., ~30%), while the rest is financed through debt (e.g., ~70%). The project-level equity contribution can in practice be funded by a mix of corporate equity and debt, depending on the company's financing structure. However, the origination of the capital deployed into the project does not affect the required project equity return, as shown in Sub-chapter 1.2.

Project financing is typically used by developers wanting to limit the equity bound up for the project on the corporate balance sheet, and to achieve higher returns on the equity deployed. Financing institutions typically require a high degree of contractual certainty, particularly regarding revenues (e.g., through long-term power purchase agreements (PPAs) or contracts for difference (CfDs)) to mitigate project risk, since their debt is secured only by the project's assets and equity.

The debt used in project financing typically varies in tenor and structure and is often provided by a syndicate of commercial banks. Loan tenors commonly range from 5 to 20 years, depending on market conditions and contract length. In some cases, developers refinance or restructure short-term construction loans after the project reaches commercial operations (COD), when construction risk has been removed and the asset can support longer-term, lower-cost financing.

Mixed financing and farm-down
A mix of balance-sheet- and project financing is used by some players; financing the project development and construction on the balance sheet, and then re-financing or divesting on project level once it has reached COD and hence have less risk.

This can be done through farm-downs, where a fraction of the project company (e.g., 50%) is sold to a third party, enabling capital recycling for the developer. It allows them to deploy equity during the riskier phases of the project – development and construction – where they have a competitive advantage in managing risk and can earn higher returns. Once the project reaches the operations phase, the risk profile declines, making ownership more attractive to long-term investors such as pension funds, who typically seek stable and lower infrastructure-like returns[3].

In practice, planning a farm-down after COD will not materially impact the hurdle rate, unless it changes the risk profile of the project cash flow from a developer perspective. Also, the market for farm-downs in offshore wind has become less favorable in recent years, primarily due to rising interest rates that have increased return requirements for long-term investors. This has narrowed the spread between the return expectations of developers and those of traditional farm-down investors, reducing the financial advantage of selling down project stakes[4]. Therefore, no impact on hurdle rate from farm-down is assumed in this report.

[2] The green premium is the lower yield investors accept (or the higher price they pay) for green bonds, reflecting strong demand, limited supply, and the perceived value of sustainable investment exposure. See more information here: LINK
[3] Infrastructure-like returns refer to the stable, lower-risk and lower-return profile typical of long-term infrastructure investments once a project is operational.
[4] The return requirements of developers have also increased with higher interest rates, but less so than those of institutional investors. This is because institutional investors are typically benchmarked against risk-free rates, whereas developers' hurdle rates do not rise proportionally with changes in the risk-free rate, as illustrated in the following subchapter.

It can be noted that there are also examples of third-party companies investing during the early stages of a project and then divesting after COD, similar to a developer's strategy. For instance, the maritime contractor Van Oord was responsible for the engineering, procurement, construction, and installation (EPCI) of the foundations and inter-array cables in the Borssele III & IV offshore wind projects. In addition to its contractor role, Van Oord held a 10% equity stake, which it divested after COD[5].

Offshore wind archetype players
Offshore wind companies can be divided into three archetype players, that in the past have tended to leverage distinct financing models:

- Utilities (Ørsted, RWE, EnBW, etc.): Have typically done balance sheet financing until COD, then kept projects on balance sheet, or performed farm-down at COD.
- Oil and gas players (TotalEnergies, Equinor, Shell, etc.): Have typically done balance sheet financing until COD and kept projects on balance sheet after that.
- Fund developers[6] (CIP, Macquarie Asset Management, GIP, Brookfield, etc.): Have typically done balance sheet financing until final investment decision (FID) and then project financing.

In addition to the categories described above, a fourth group of niche developers can be identified. These companies typically specialize in specific geographies, technologies, or stages of the development cycle, and rely on partnerships to complement their capabilities. Examples include Flotation Energy, Fred. Olsen Seawind, and Deep Wind Offshore. However, this category is not expected to materially affect hurdle rates or business cases, as these developers generally partner with larger players who drive the overall financing structure. For simplicity, they are therefore excluded from further analysis.

The offshore wind industry has experienced significant changes over the last 2-3 years, impacting the choice of financing model, with the following factors being important:

- The less favorable farm-down market has made the balance-sheet-to-COD-then-farm-down model less attractive.
- Companies have generally revised their strategies, with higher requirements for profitability instead of growth-focus, and strategies to limit CapEx on the balance sheet.
- Some companies have seen their credit rating drop, generally increasing the cost of capital on corporate level, making project financing relatively more attractive.
- There has been a push from the industry and EU[7] to re-introduce CfDs to reduce revenue risk in markets like Denmark, Netherlands and Germany, with project financing being more viable if implementing such schemes compared to merchant power price exposure.

The changes outlined above make project financing relatively more attractive. The choice of financing model will, however, continue to vary across developers and will be assessed on a project-by-project basis.

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[5] See more information about the example here: LINK
[6] The mentioned funds own developer functions that perform the development of the projects; CIP owns Copenhagen Offshore Partners, Macquarie owns Corio, GIP owns Skyborn, and Brookfield owns Brookfield Renewables.
[7] See more information on the EU Electricity Market Design (EMD) here: LINK

1.2 Methodology for determining hurdle rate

Disclaimer: The methodology presented in this section is intended as a general framework for determining post-tax hurdle rates for offshore wind projects. It should not be viewed as a universal or prescriptive model. Actual approaches may vary across developers and financial institutions depending on company-specific policies, capital structures, and risk assessments.

The framework used in this report provides a consistent logic for calculating hurdle rates over the lifetime of an asset at the project level. A clear distinction is made between balance sheet financing and project financing approaches. Below is an explanation of how each of the different parameters can be calculated for each of the two different financing models, while an example of how the framework can be applied in practice is provided in Chapter 3.

Methods for including risks in business cases
Note that the method for calculating hurdle rates varies between developers, as there are different approaches to incorporate risk in decision making. Below is an overview of the different methods, the risks that are usually treated under each of them, and how the risks are treated in the methodology applied. It is possible to separate between the risks that impact the cost of capital on corporate level, and the project-specific risks. This can be seen in the balance sheet financing hurdle rate calculation (Equation 1) further below.

- Include risk in hurdle rate: Premiums related to broader risk categories that influence investors' expected return, rather than the specific project contingencies that impact realized cash flows. Commonly applied for risks such as:
  - Market risk premium (the volatility of the overall market relative to a risk-free rate). Reflected in the parameter *MRP* in Equation 1 and 2 below.
  - Technology risk (the risk of the specific offshore wind project compared to other alternative investments such as solar PV and onshore wind). Reflected in the parameter *TEC* in Equation 1 and 2 below.
  - Commercial risk – price risk (the risk related to uncertainty on future capture prices of the specific offshore wind project)[8]. Reflected in the parameter *COM* in Equation 1 and 2 below.
  - Regulatory risk – country risk (the additional return investors require to compensate for the political, economic, and institutional risk of the country of which the specific risk is located). Given that Denmark is the scope of this exercise, no country risk is included, as it is mostly used for emerging markets outside western Europe.

- Include risk as contingency: Buffer in the business case calculations[9] related to specific input parameters directly impacting the cash flow of the specific project. Commonly applied for risks such as:
  - Delivery risk – supplier risk (the uncertainty on the future cost of equipment and services, the availability of new technology, and considerations on potential supply chain bottlenecks for the specific project).

[8] Note that the risk related to total volume of production, including curtailment is not reflected in this parameter, but rather in the business case through a buffer on the power production (more conservative assumption to account for risk). See Sub-chapter 2.2 for further details.
[9] Business case calculations refer to the full model developers would usually apply to calculate IRR, NPV, and other relevant project performance indicators.

- Delivery risk – construction risk (the risk related to challenges during installation, potential delays, and coordination with other stakeholders for the specific project).
- Financial risk – interest-, inflation-, and currency risk (the risk of prices/interest rates increasing and/or exchange rates changing between auction participation and FID for the specific project).
- Commercial risk – production risk (the uncertainty related to volume of production from the specific wind farm, including potential curtailment imposed by TSO[10]).

- Include risk as qualitative assessments: No quantification of risk in the business case, but considered when making the decisions on whether to move the project forward or not. Commonly applied for risks that are not easily quantifiable and/or have a binary impact on project decisions, meaning that they can be significant enough to not move forward with the project. Commonly applied for risks such as:
  - Regulatory risk – tender criteria (the risk of obligations in the tender resulting in a high, non-quantifiable cost for the specific project).
  - Financial risk – project size (the risk of having high financial exposure to one large project, "putting all eggs in one basket").

In Equation 1 and 2 below, it is assumed that market risk, technology risk, and the commercial price risk are reflected in the hurdle rate, while the risks related to suppliers, construction, finance, and power production are included as contingency in the business case. Note that a thorough step-by-step approach for obtaining each of the parameters that go into the calculations is described in Appendix C.

Balance sheet financing

The hurdle rate when doing balance sheet financing can be calculated as the sum of weighted cost of debt and the weighted cost of equity on the balance sheet, with the technology and commercial risk factors of the specific project added, plus a margin on top:

Equation 1 Hurdle rate for a project when doing balance sheet financing (H_{BS})

$$H_{BS} = \underbrace{\frac{D_{BS}}{V_{BS}} \times \left[\left(1 - Tax_{Corp}\right) * \left(r^f + DRP_{BS}\right)\right] + \frac{E_{BS}}{V_{BS}} \times \left(r^f + \beta_{levered,BS} \times MRP\right)}_{\text{Company WACC}} + \underbrace{TEC + COM}_{\text{Project-specific risk premiums}} + \underbrace{MAR}_{\text{Margin}}$$

[10] Note that the risk of curtailment can alco be considered as a qualitative assessment in addition to the buffer in the business case, particularly if the risk is significant and challenging to quantify.

Parameter	Explanation
$\frac{D_{BS}}{V_{BS}}$	Share of debt (D_{BS}) on balance sheet level (as fraction of total enterprise value V_{BS}[11]).
Tax_{Corp}	Corporate income tax rate for each developer in their country of origin.
r^f	Risk-free rate (e.g., 30-year Danish government bond index).
DRP_{BS}	Debt risk premium – the add-on to the risk-free rate reflecting the market's view on risk of issuing debt to the company, often reflected by the credit rating.
$\frac{E_{BS}}{V_{BS}}$	Share of equity (E_{BS}) on balance sheet level (as fraction of total enterprise value V_{BS}).
$\beta_{levered,BS}$	Levered beta reflects the volatility of a stock relative to the entire market and is a company-specific value. For companies investing in several different technologies (e.g., oil and gas), adjusting this value to reflect the relevant volatility for renewable energy investments is important (further explained in Appendix C).
MRP	Market risk premium reflects the returns an investor expects to earn by investing in the overall stock market in the relevant country instead of a risk-free asset.
TEC	Technology risk premium reflects the additional technology risk of the specific offshore wind project over investments in other renewable energy projects. Note that this assumes that the beta value has already been adjusted to reflect the volatility of the companies' renewable energy investments, as described above.
COM	Commercial risk premium reflects the risk related to uncertainty about future offshore wind capture prices. This premium will be significantly higher if the project is exposed to merchant power prices versus a CfD or a long-term PPA. The size of the premium will depend on type of player, fraction of revenue that is exposed to merchant power prices, and duration of potential state offtake support/ PPA.
MAR	Margin – any margin the developer would require, on top of the cost of capital and project-specific risk premiums. The margin will in most cases be positive (providing an upside for the developer) but can be zero or even negative if the developer views the project as a strategic must-win in a competitive auction.

Table 1 Parameters included in the calculation of hurdle rate when performing balance sheet financing

[11] Enterprise value (here denoted as V_{BS}) represents the total value of a company's core business, reflecting what it would cost to acquire the entire firm – including both its equity and debt – while accounting for any cash the company holds.

Project financing

The approach for calculating the hurdle rate in a project financing model follows the same general principles as in balance sheet financing, with the key distinction that debt and equity are assessed at the project level rather than at the corporate level. The project-specific risk premiums represented by TEC and COM affect only the equity component of the calculation, as lending institutions apply their own methodologies to determine the risk premiums embedded in the cost of debt. The hurdle rate for project financing is therefore calculated as follows:

Equation 2 Hurdle rate for a project when doing project financing (H_P)

$$H_P = \underbrace{\frac{D_P}{V_P} \times [(1 - Tax_{Market}) * (r^f + DRP_P)]}_{\substack{\text{Weighted cost of project debt} \\ \text{(from lenders)}}} + \underbrace{\frac{E_P}{V_P} \times \left(r^f + \beta_{levered,P} \times MRP + TEC + COM\right)}_{\substack{\text{Weighted cost of project equity} \\ \text{(from developer)}}} + \underbrace{MAR}_{\text{Margin}}$$

Parameter	Explanation
$\frac{D_P}{V_P}$	Share of debt (D_P) on project level (as fraction of total project value V_P).
Tax_{Market}	Corporate income tax rate applied in the market of the project (Denmark).
r^f	Risk-free rate (e.g., 30-year Danish government bond index).
DRP_P	Project debt risk premium – the additional yield over the risk-free rate required by the lender (bank) reflecting perceived credit risk of the project.
$\frac{E_P}{V_P}$	Share of equity (E_P) on project level (as fraction of total project value V_P).
$\beta_{levered,P}$	Levered beta for the project reflects the volatility of project equity returns relative to the overall market and is specific to the project's risk and capital structure (further explained in Appendix C).
MRP	Market risk premium reflects the returns an investor expects to earn by investing in the overall stock market in the relevant country instead of a risk-free asset.
TEC	Technology risk premium reflects the additional technology risk of the specific offshore wind project over investments in other renewable energy projects. Note that this assumes that the beta value has already been adjusted to reflect the volatility of the companies' renewable energy investments, as described above.
COM	Commercial risk premium reflects the risk related to uncertainty about future offshore wind capture prices. This premium will be significantly higher if the project is exposed to merchant power prices versus a CfD or a long-term PPA. The size of the premium will depend on type of player,

	fraction of revenue that is exposed to merchant power prices, and duration of potential state offtake support/ PPA.
MAR	Margin – any margin the developer would require, on top of the cost of capital and project-specific risk premiums. The margin will in most cases be positive (providing an upside for the developer) but can be zero or even negative if the developer views the project as a strategic must-win in a competitive auction.

Table 2 Parameters included in the calculation of hurdle rate when performing project financing

It can be noted that the risk-free rate affects both the cost of debt and the cost of equity in the calculation above (and similarly for balance sheet financing). In this analysis, the risk-free rate is represented by the yield on a 30-year Danish government bond index, as described further in Appendix C. The yield on this long-term government bond reflects market expectations of future Danish central bank policy rates, along with inflation expectations and a term premium for holding long-duration assets. When the central bank changes its policy rate, the government bond yield typically moves in the same direction, but the adjustment is usually smaller, since long-term rates depend mainly on expectations of policy rates over the full 30-year horizon rather than the current rate alone.

For project financing, the share of debt will be lower, and the share of equity higher the riskier the project is, and vice versa. Projects with an uncapped CfD-scheme providing full price certainty for 15-20 years duration often enable a debt share of around 70-75%, while projects with full merchant power price exposure often imply that banks will only be willing to offer a lower share of debt.

A project with higher risk will often have a higher cost of debt, in addition to requiring a lower share of debt financing compared to a less risky project. Banks will consider the same risks as developers, but will generally be more conservative on the key assumptions in the business case, and in their assessment of risks. Given the more conservative assumptions, and the fact that project losses are first absorbed by project equity, banks would typically have lower return expectations than developers. Generally, the cost of debt at company-level for developers can be used as a starting point for determining cost of debt at project-level, with an added risk premium. This is further explained in Appendix C.

It should be noted that developers are a heterogeneous group with very different prerequisites for offshore wind development. There are significant differences in their capital structures, financing costs, and risk assessments, all of which influence their business cases. Utilities that also operate grid businesses typically have access to relatively inexpensive debt, whereas pure-play offshore wind developers have been more affected by increasing uncertainty in offshore wind and rising interest rates[12]. Oil and gas companies have raised their return requirements due to alternative investment opportunities with higher yields, such as oil and gas production. Infrastructure and financial investors generally face higher capital costs and a different risk profile. As a result, both the sophistication and methodology applied in calculating hurdle rates vary across developer types.

[12] Utilities with grid business typically benefit from strong balance sheets and diversified revenue streams with high certainty, that makes them lower-risk borrowers. Pure-play offshore wind developers are more directly exposed to fluctuations in the industry.

Alternative approaches for determining hurdle rates
As mentioned previously, the method for determining hurdle rates for offshore wind projects vary between developers. This report will not go into the details of alternative methods to the two that are outlined above. However, it can be mentioned that some developers apply significantly simpler methods than what has been shown in this report. In practice, this could be a fixed hurdle rate that the projected IRR of projects must meet. Risks are then only included as contingency in business cases, and as qualitative considerations on whether to pursue the project or not.

1.3 Impact on hurdle rate from different support scheme options

The support scheme options included in the assessment below are a two-sided cCfD model and an FIP model. The support scheme options will mainly impact the commercial risk of the project, compared to not having any support scheme, and thereby impact the hurdle rate of the project through the parameter COM (and the DRP_P if doing project financing).

It can be assumed that the cost of debt if doing project financing will be the same for all developers, assuming the share of debt and the project details are the same (although in practice, larger and financially stronger corporations will typically have slightly better terms than smaller developers). The COM-parameter will, however, vary between developers. Typically, utilities and funds will add a risk premium (2.0-3.5 pp.) if having merchant power price exposure, while some oil and gas companies will add less risk (0-1.0 pp.). The reason is that oil and gas companies have a higher tolerance for power market exposure, and greater ability to optimize the value of electricity across a broader energy portfolio.

If having a cCfD without any budget cap, the developers will generally set the COM-parameter to zero for the years of duration of the cCfD, while applying a hurdle rate including the merchant power price risk premium after the duration of the cCfD. The result is a lifetime hurdle rate – the one that is used for calculating the return requirements of the project over its lifetime – of the projects being defined by a weighted, discounted average of the two[13]. Similarly, a bank would allow a higher share of debt and a lower cost of debt in such a case. Compared to a standard, two-sided, production-based CfD, the cCfD is likely to add some risk for the first auctions, since there is uncertainty from the developer side on whether the calculation of capability will be fair, and how the system will function in practice. Nevertheless, it is expected that this risk will not be substantial and can be neglected for all practical purposes.

An advantage of a cCfD over a production-based CfD, is the de-risking of both prices and volume. This feature is particularly important for hybrid offshore wind farms, that are exposed to the risk of reduced transmission capacity of interconnectors. As outlined in Sub-chapter 1.2, the effect of this risk mitigation is typically reflected through a reduction in the power production in the business case rather than through an adjustment of the hurdle rate.

An FIP does not provide the same risk relief as a cCfD from a developer perspective, as it is an add-on to power prices that does not provide price certainty. Although it will strengthen developers' business cases, the primary risk-mitigating advantage lies in securing a floor price, provided that power prices are not expected to fall materially below zero. The commercial risk premium (COM) and the debt risk premium (DRP_P) will therefore be higher than for a cCfD, but lower than a case with full merchant power price exposure. From a government perspective, the

[13] The lifetime hurdle rate captures the risk in both the construction phase (through cost of equity/ debt and TEC) and the operational phase as described.

FIP has the advantage of providing more certainty than an uncapped cCfD on the magnitude of budget that will be spent.

Having a budget cap on state support will significantly impact both the commercial risk premium (COM), and the debt risk premium (DRP_P) under a cCfD. Both developers and banks will in such a case apply estimates for offshore wind capture prices and production and calculate the likely duration of government support. A case with a 20-year cCfD-agreement but a budget that will likely run out after 10 years under these assumptions, will from a developer perspective imply a higher weighting of the merchant-exposed hurdle rate, due to a lower fraction of the revenue being de-risked. The lifetime hurdle rate will therefore be higher[14]. Similarly, banks will require a higher share of equity and/or require a higher interest rate if a lower share of the revenue is exposed to power price certainty. Typically, banks will apply conservative assumptions across the business case (particularly for power prices) resulting in more rapid depletion of the support budget compared to what developers have in their business cases.

An interesting dynamic arises with cCfD support budget caps: a lower cap increases risk from both a developer and a bank perspective. This will lead to both higher cost of debt and a higher commercial risk premium, leading to higher hurdle rates. Consequently, higher support through an increased cCfD strike price will be required. Setting a higher support budget cap from a state perspective could therefore lead to less budget spent in the end, but a higher variance of budget spend, assuming all else equal (including the expected duration of support payments).

However, a lower budget could result in a quicker payout of the state support if developers choose to bid high strike prices. Therefore, an opposing effect to the higher hurdle rate, is that the more rapid payout of the subsidy with a high strike price impacts the business case of developers positively. This is due to the fact that the present value of the support is higher when receiving it earlier in the project lifetime. An example of this dynamic was seen in the Sørlige Nordsjø II tender in Norway in 2024. The strike price of the CfD was 115 øre/kWh, with analysts predicting that the budget will be depleted after 6-7 years, despite having a duration of the CfD scheme of 15 years.

In sum, developers would always prefer a higher support budget cap, but receiving the support earlier through a high strike price could enable viable business cases if support budgets are too low to enable an adequate support level over the full support period.

For the FIP, a support budget cap does not materially impact the risk profile of the project, since the magnitude of payout is not linked to the uncertain power price. Because the only parameter affecting the payout is the total production of the wind farm, developers can with relatively high certainty predict when the budget will be exhausted.

1.4 Step-by-step guide to determine the hurdle rate to be applied in business cases

The steps to determine a hurdle rate to be applied in business cases are summarized below on a high level, providing the practical logic for applying the methodology described above. Chapter 3 provides a more concrete description of these steps applied on EØB.

The methodology can be divided into five steps:

A. Define the support schemes to determine the hurdle rate under (e.g., cCfD, FIP, full merchant exposure).

[14] See Appendix C for further explanation on how the weighted hurdle rate is calculated.

B. Determine the likely financing model (balance sheet financing vs. project financing) applied by developers under each support model.
C. Estimate hurdle rates for a representative selection of offshore wind developers, with the methodology described. Calculate the average hurdle rate for each archetype developer (utilities, oil and gas players, developer funds) under each relevant support scheme.
D. Determine hurdle rate ranges to be tested with the market for each of the relevant support schemes. Values representing the average of the hurdle rates for each of the three archetype developers can be applied, or one can choose to select the highest if wanting to increase the likelihood of attracting multiple bidders.
E. Most important: Test the hurdle rates with the market and calibrate if needed. It is generally challenging to estimate hurdle rates bottom-up, and dialogue with relevant developers and banks is considered a key step. This is usually done by presenting developers to relevant ranges of hurdle rates and asking them to comment on whether the ranges are in line with what they would expect.

For future projects, a more pragmatic approach to determining hurdle rates can be adopted – namely, by applying the values calculated in this report and proceeding directly to step E) described above. To stimulate market discussion, the hurdle rate ranges presented in meetings can be set 1.0 pp. lower than those calculated in this report. This approach can enable constructive reactions and challenge developers on their required returns for offshore wind projects. This pragmatic approach is recommended as it will save a substantial amount of effort and is likely to result in a robust outcome.

2 Methodology for determining support budget cap

This chapter outlines the methodology used to determine the support budget cap for offshore wind projects from a state perspective. By design, it does not include detailed business case calculations or underlying assumptions; considerations around these topics are addressed in Chapter 3, while Appendix C describes how to derive the necessary input parameters.

The chapter begins with a brief overview of alternative state support models for offshore wind. It then presents the methodology for establishing the support budget cap, including guidance on sensitivity analyses to assess the buffer between the most likely support requirement and the budget cap.

2.1 Options for providing state support for offshore wind projects

There exists a range of different options for providing state support for offshore wind projects. The list below describes the most important ones briefly and should not be viewed as an exhaustive list of state support models.

Contract for difference: Most common in the format of a two-sided[15] CfD with a premium that tops up revenue when the wholesale power price is lower than strike price and pays back when the power price is higher than the strike price. Several configurations exist, with the most common format calculating payments based on the produced volume of electricity. This fully mitigates the merchant power price risk for developers. A capability-based CfD will on the other hand calculate payments not based on the produced volume of electricity, but rather on the estimated capability to produce electricity. As mentioned, this mitigates also the volume risk for

[15] One-sided CfDs provide a top-up to the strike price, without payback when power prices exceed the strike price. This format is less common in current offshore wind markets.

developers. Two-sided production-based CfDs are applied in countries like the UK and Norway, while Belgium has approved the capability-based CfD for future offshore wind tenders. Other configurations include yardstick CfDs and financial CfDs but these will not be further explained in this report[16].

Fixed offtake price: The State purchases the electricity produced under a fixed tariff agreed through a long-term contract. From a developer's perspective, this model is similar to a two-sided CfD, as it provides stable revenues and eliminates exposure to wholesale price fluctuations. Such schemes are applied in, for example, the United States, where several states use Offshore Renewable Energy Certificate (OREC) mechanisms that effectively guarantee a fixed price per MWh.

Feed-in premium: The developer receives a premium on top of the wholesale power price. It can either be a fixed premium, or it can be a premium varying with the market prices. Often, the feed-in premium is granted for a certain volume of production, or a fixed number of years. This support scheme has been applied in the past for multiple Danish offshore wind projects.

Investment support: The developer receives a lump-sum grant from the State to partially cover the project's investment costs. The support is typically disbursed in several instalments – a first payment could be already at FID, while the remaining support amount could be paid upon commercial operation or after a defined period of stable operations (e.g., one year). An investment support model is planned for the Utsira Nord floating offshore wind tender in Norway, which is being conducted in two stages: first, the award of lease areas, and subsequently the allocation of state investment support through a competitive process[17].

Tax credits: Under this model, developers receive reductions in tax liability based on either the capital investment or the electricity produced from the project. The support is realized through deductions or refundable credits that lower a company's payable tax, or, for tax-exempt entities, via direct payments of equivalent value. This model is widely used in the United States under the Inflation Reduction Act (IRA), which introduced technology-neutral incentives for renewable energy.

Government loans: Under this model, a government institution – often through a public financial institution – provides loans to reduce financing costs and improve bankability for offshore wind projects. The loans are typically offered on favorable terms, such as lower interest rates, longer repayment periods, or deferred repayment during construction. The European Investment Bank (EIB) has previously issued such a loan for the Thor offshore wind farm, while Sweden has recently announced the use of state loans in combination with CfDs to enable nuclear energy build-out.

In this report, only the cCfD and FIP models are evaluated, as they are considered the most viable options in Denmark given EU-regulations and political consensus.

2.2 Methodology for determining support budget cap

The following methodology presents a step-by-step approach for calculating the support budget cap for governmental purposes. The process for determining the hurdle rate is not included here, as it is described in Chapter 1.

[16] See this article for more information: LINK

[17] The application deadline for the lease-area tender was September 2025.

I.) Calculate the business case without any state support
To determine the support budget cap for an offshore wind project, a developer-perspective business case is modelled using a discounted cash flow (DCF) approach. As is standard practice, all cash flows are discounted to the year of the FID, which has also been applied in this analysis.

This step serves as the starting point for calculating the support requirements in the next step. It should be noted that the hurdle rate for the fully merchant case presented in this step is higher than for a case with a support scheme. The objective here is therefore not to compare the merchant business case with the business case with a support scheme, but to establish a baseline from which the necessary level of support can be determined in the subsequent step. No considerations are therefore made in this step on what level of support that is needed to realize a merchant business case.

The business case reflects the expected costs and revenues associated with the project, including estimated production and the anticipated capture price for offshore wind. Business case assumptions naturally vary among developers, and there is no single method that ensures full representativeness. The key input parameters of a standard offshore wind business case are described below.

<u>Costs and contingency:</u>

- **Development Expenditure (DevEx):** This typically includes all costs incurred by the developer prior to the final investment decision (FID), such as tender preparation, site investigations and surveys, engineering and design work, and legal/permitting expenses. The magnitude of DevEx can vary significantly between projects but generally represents a single-digit percentage of total CAPEX. Most developers allocate DevEx directly to individual projects and discount these expenditures forward to the FID date when evaluating project economics.
- **Capital Expenditure (CapEx):** This covers all investment costs incurred after the final investment decision (FID) until the project reaches commercial operation. CapEx typically includes the procurement and installation of turbines, foundations, inter-array- and export cables, substations, and grid connection infrastructure, as well as construction management and commissioning activities. For offshore wind projects, CapEx generally represents the by far largest cost component. The level of CapEx depends on factors such as project size, site conditions, water depth, and distance to shore.
- **Operational Expenditure (OpEx):** This includes all costs incurred during the operational phase of the project, from commercial operation until decommissioning. OpEx covers operation and maintenance (O&M) activities, such as scheduled and unscheduled turbine servicing, inspections, spare parts, and vessel costs, as well as lease payments, insurance, administration, and onshore support functions.
- **Abandonment Expenditure (AbEx):** This represents the costs associated with decommissioning and site restoration at the end of the project's lifetime. It typically includes removal of turbines, foundations, cables, and substations, as well as transport, recycling, and disposal activities. AbEx is often based on a fixed percentage of CapEx (commonly in the range of ~5%). The actual cost can vary depending on site conditions, water depth, and decommissioning strategy.
- **Contingency:** As outlined in Chapter 1, uncertainty on costs related to supplier risk, construction risk, and financial risk are often included in business cases through contingency. For developers, this usually includes assessing the uncertainty of each cost parameter of the business case and then adding corresponding contingency. When

procuring data from a third-party supplier, this is often reflected in an overarching contingency on CapEx, typically around 5-10%[18].

Power production:

- **Annual power production:** This represents the expected annual electricity generation of the offshore wind farm. Power production estimates are typically derived from wind resource assessments based on long-term meteorological data, wake modelling, and loss factor analyses that account for turbine performance, electrical losses, and availability. The key metric is the net annual energy production (AEP), often expressed as capacity factor. Power production in business cases usually accounts for expected variations in availability and performance of the wind farm during the lifetime.
- **Buffer on production:** To account for uncertainty related to production, a buffer reflecting a more conservative estimate can be added in business cases. This is also the case if assuming lost power production due to, e.g., curtailment. Normally, the most likely production value is applied in the base case for developers (no buffer), while a more conservative estimate is used for sensitivity calculations, and by banks when issuing debt for a project.

Power prices:

- **Offshore wind capture prices:** This represents the average annual price that an offshore wind farm is expected to realize when selling electricity to the wholesale market for each year in the lifetime of the project. Capture prices reflect not only the overall level of wholesale power prices but also the timing and correlation between generation and market prices – essentially, how often the wind farm produces during periods of high or low prices. Capture prices are typically estimated through advanced power market simulations covering a large, interconnected region (e.g., Northern Europe for Danish projects). These models incorporate assumptions on the future development of the power system, including fuel and carbon price trajectories, grid expansion, interconnector capacity, renewable build-out, demand growth, and market coupling effects. Many offshore wind developers have dedicated power price modeling teams, that work on modeling long-term power price development. However, if obtaining external funding for a specific project, estimates from trusted third-party analysis firms are usually applied.
- **Uncertainty on power prices:** The uncertainty on future development of power prices is typically reflected in the hurdle rate of the project, as outlined in Chapter 1.

Taxes:

- **Corporate taxes paid from the project:** This represents the corporate income tax payable on profits generated by the project. Estimating tax payments for offshore wind projects can be challenging, as developers often employ tax optimization strategies that reduce their effective tax burden. In this report, all hurdle rates are stated on a post-tax basis, reflecting developers' return requirements after tax payments. Consequently, the calculated support requirement represents the subsidies needed to achieve these post-tax returns. For modelling purposes, a straight-line depreciation of CapEx and DevEx over 20 years from COD (i.e., 5% per year) is applied, together with a 22% Danish corporate tax rate. This assumption likely leads to an overestimation of the required support, since developers typically face a lower effective tax rate due to tax optimization. To illustrate this effect, an alternative case with no taxes paid is also included in Chapter 3.

[18] Note that contingency will depend on the stage in the development cycle, and the uncertainty on input parameters. Emerging technologies like floating offshore wind will typically have higher contingency included in business cases.

The assumptions for costs and power production have been sourced from a trusted third-party data provider and subsequently refined through dialogue with industry stakeholders and BCG's own market expertise. Power price assumptions have likewise been obtained from a reputable third-party analyst firm. These considerations are described in greater detail in Chapter 3, and in Appendix C.

Generally, it is important to obtain input data to the model that is as similar as possible to what developers will likely use in their business cases. It is therefore essential that the key business case assumptions are updated as late in the tender preparation process as possible and vetted with developers and third-party providers. This can be done in the same round of meetings as for testing the level of hurdle rates, as described in Chapter 1.

In a business case, the most important input parameters – such as CapEx, OpEx, power production, and power prices – are uncertain and can take on a range of possible values rather than a single fixed number. To reflect this, each parameter is in a best-practice business case described with a probability distribution showing how likely different outcomes are. The base case is usually built using the most likely estimates (often called P50 values), meaning there is roughly a 50% chance that the actual value will be higher or lower. By combining these ranges, one can run simulations to see how the overall project result – such as IRR or NPV – might vary under different conditions.

However, reliable data for such probability ranges can be challenging to obtain. Therefore, we apply this logic only in an approximate form for hurdle rate, CapEx, and balancing costs in the scenarios applied for estimating the budget cap, described in Step (IV). These approximations are based on dialogue with the market and internal BCG knowledge. The parameters that are approximations for probability distributions are marked with quotation marks (e.g., "P90")[19].

II.) Calculate the support requirements under each relevant support scheme
Once the unsubsidized business case has been established, the level of state support required to achieve an IRR equal to the target hurdle rate for each support scheme can be determined. In practice, this is done by using a solver (e.g., Microsoft Excel's Goal Seek function) to identify the value of the cCfD strike price or FIP that aligns the project's calculated IRR with the required hurdle rate. The resulting total support requirement is then calculated as the non-discounted sum of the subsidy paid out each year, given the strike price/ feed-in premium. This is from now on referred to as the *base case support requirements.*

III.) Run sensitivity analyses on the most important input parameters
To understand the range of possible support requirements, sensitivity analyses should be conducted for the key input parameters – particularly those that have the strongest influence on the business case and therefore on the level of required support. Now, only the most relevant support scheme should be selected to avoid running too many sensitivity analyses.

The most important sensitivities that are commonly run for all projects are:

- CapEx – typically the parameter with the highest sensitivity, reflecting both its large share of total costs and the uncertainty of future price developments.
- OpEx – generally less sensitive than CapEx, but often included due to potential variation in maintenance strategies, inflation, and service costs.

[19] For the power price estimates, an estimated probability distribution has been obtained from the third-party vendor, and they are therefore shown without quotation marks (e.g., P90).

- Hurdle rate – a key financial parameter that varies between companies and projects, depending on risk appetite and financing structure.
- Power production – depends on assumptions regarding wind resource, wake effects, availability, and curtailment, all of which carry inherent uncertainty.
- Power prices – strongly influenced by assumptions on the future development of the power system and therefore subject to variation across forecasts.
- Balancing costs – historically not a common sensitivity parameter, but increasingly important given the high volatility of current balancing markets and the uncertainty around future price levels.
- Construction delay – captures the impact of delayed revenues and any penalties associated with a later commercial operation date (COD).

In addition to the standard sensitivities described above, project-specific sensitivities can also be assessed. The below examples are relevant for Danish offshore wind tenders:

- Market access in early years – reflects the potential impact of an extended testing or commissioning period for related grid infrastructure, which could limit the volume of power sold to the market during the first years of operation. This sensitivity is particularly relevant where there is uncertainty from the TSO regarding market access.
- Cost of shared infrastructure – relevant if no final decision has been made on how the costs of common assets (e.g., transmission links or onshore grid reinforcements) will be allocated between developers and government entities.
- Support scheme configuration – important if the design parameters of the support mechanism have not yet been defined, such as the duration of the scheme, the timing of support payments, or the indexation of the strike price.

Additional financial sensitivities such as inflation, interest rates, and exchange rates can also be run, but are for the sake of simplicity left out of the overview above. Also, sensitivities on costs related to fulfilling certain tender criteria (e.g., local sourcing, sustainability, security) can be included but will vary between tenders.

No sensitivities are included for risks typically addressed through qualitative assessments, such as project size or risks associated with specific non-quantifiable tender criteria. These factors are generally not quantified by developers (as noted in Chapter 1), and quantitative sensitivity analyses are therefore not considered relevant for them.

IV.) Determine scenarios to calculate the support budget cap
To ensure a high probability of receiving bids from multiple developers in a potential tender, the budget cap should normally include a buffer on top of the base case support requirement. This buffer accounts for uncertainties in the underlying assumptions of the business case and for differences in cost- and risk assessments across developers. Conversely, if a higher level of uncertainty regarding tender competition is acceptable, the buffer can be smaller – or even negative. The magnitude of the buffer is further explained in Step (V).

One approach to defining the support budget cap is to develop three scenarios based on the key sensitivity parameters and set the support budget cap equal to the support requirements in each of them. There are several ways to construct such scenarios, with the recommended approach illustrated in Figure 2-1. The value of the specific parameters applied in each scenario should be determined on a case-by-case basis, depending on project characteristics and data availability. The logic for getting to the parameter values used for this report is described below, with the three suggested scenarios:

Low-support scenario:
Base case assumptions, with the following adjustments;

- Lower hurdle rate estimate: Reflects a return requirement expected to be at the lower end of what developers would require to build the project[20]. This can be called a "P90 value", meaning that the probability of developers having a hurdle rate lower than this is very low.
- Lower CapEx estimate: Similarly, as for hurdle rate, this reflects a "P90 value" for CapEx, being on the very lower end of what developers would expect.

Mid-support scenario:
Base case assumptions, with the following adjustments;

- Slightly lower power price estimate: Corresponds to a P60 estimate from the third-party power price provider, reflecting moderately lower market prices than the base case.
- Slightly higher CapEx estimate: Represents a "P40 value" for CapEx, i.e., a moderately higher cost level compared to the base case. The value was approximated by linear interpolation as follows:

  $$\text{P40 value} = \text{P50 value} + \frac{40\%-50\%}{90\%-50\%} \times (\text{P90 value} - \text{P50 value})$$

- Slightly higher balancing cost estimate: Reflects a "P40 value", corresponding to a situation where balancing costs stabilize at somewhat higher levels than in the past. The same interpolation approach as for CapEx is applied.

High-support scenario:
Base case assumptions, with the following adjustments;

- Low power price estimate: Corresponds to the P90 estimate from the third-party power price provider, representing the lower end of the expected capture price range.
- High CapEx estimate: Represents a "P10 value" for CapEx, i.e., the upper end of expected investment costs, reflecting a situation with cost escalation or supply-chain pressure.
- High balancing cost estimate: Reflects a "P10 value" corresponding to a situation where balancing costs remain persistently higher than historical levels, though without the extreme short-term volatility seen the last year.

Note that the described methodology above adds some complexity introducing proxies for probability distributions for hurdle rate, CapEx and balancing costs based on dialogue with the market and general BCG market knowledge. This approach is easier to understand when applied for the EØB estimates presented in Chapter 3.

Scenarios can be built in a simpler manner than described above by applying sensitivities such as +-10-20% for CapEx, +-20% for power prices, and +-3-10 EUR/MWh for balancing costs. There is no right or wrong scenarios – they depend on the parameters viewed a most critical for the specific project, and the ranges viewed as realistic from the starting point of the base case. The method will generally still be valid if choosing to exclude one or several sensitivities in the scenarios or replacing them with other sensitivities.

[20] Based on the discussions with relevant developers.

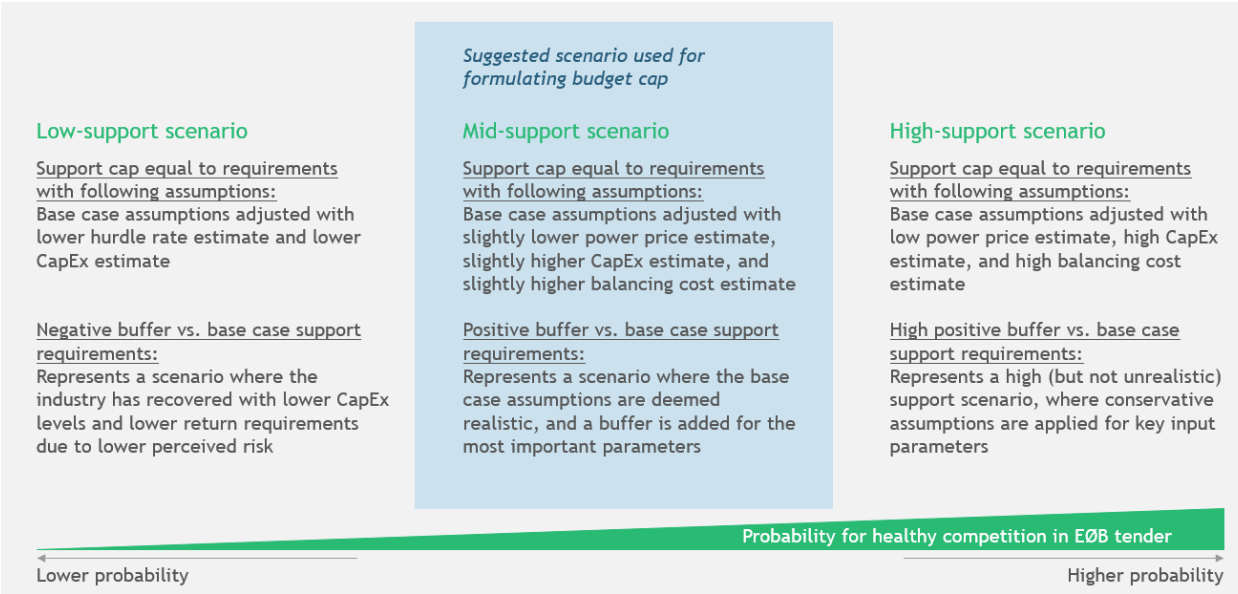

Figure 2-1 Scenarios to determine support budget cap

V.) Calculate the support budget cap
The support requirements to reach the target hurdle rate can be calculated for each of the three scenarios, assuming a 20-year duration of the support scheme. If the support budget cap is set equal to the requirement in the Mid-support scenario, it provides a buffer between the base case support requirements and the support requirement with the more conservative assumptions applied in the Mid-support scenario.

The payout profile of the scheme affects the required budget cap. If developers bid a higher strike price, the subsidies will be paid out faster, potentially exhausting the budget before the intended 20-year period. This dynamic generally improves the developer's business case, as receiving positive cash flows earlier reduces the required overall support.

To capture this effect, the support requirement should also be modelled under shorter payout horizons – for example, 10 years, 5 years, or an extreme case where the entire subsidy is paid at COD. In such cases, the lifetime hurdle rate must be adjusted to reflect the higher exposure to the merchant risk faced after the cCfD payments expire. This leads to a higher effective hurdle rate compared to a 20-year support scheme. Similarly, the volume certainty provided by the cCfD will apply for a shorter period. Beyond this period, the business case must be adjusted for expected losses related to, e.g., limited interconnector capacity and other potential constraints on power export.

The final budget cap can then be selected from the results under the Mid-support scenario, depending on whether the State intends to pay the subsidies over the full 20-year period or is willing to allow a shorter payout horizon. These trade-offs are discussed in Sub-chapter 2.3, in Chapter 3, and with a step-by-step approach presented in Appendix C.

3 Likely hurdle rate and support budget cap for EØB

This chapter begins with an introduction to EØB, focusing on the characteristics relevant for modelling the business case from a developer perspective. Thereafter, focus shifts to estimating the hurdle rate of the project through the methodology described in Chapter 1. Finally, the support requirements and corresponding support budget cap are shown.

Note that values such as power prices, costs, strike prices, and feed-in premiums are shown in Euros, since this is the currency applied by developers in business case calculations. The support requirements from the Danish state are on the other hand always shown in DKK (real 2025), since this is the currency that will be applied for subsidies[21].

3.1 EØB project description

EØB is a hybrid offshore wind project comprising 3 GW of planned capacity connected to the island of Bornholm. Energinet will install a 1.2 GW interconnector from Zealand (DK2 price zone) to Bornholm, while 50Hertz will construct a 2 GW interconnector linking Bornholm to Germany. The offshore wind project and Bornholm is planned to be included in a new DK3 power price zone. First generated power from the project is expected in 2034, with all 3 GW in full operations from 2037.

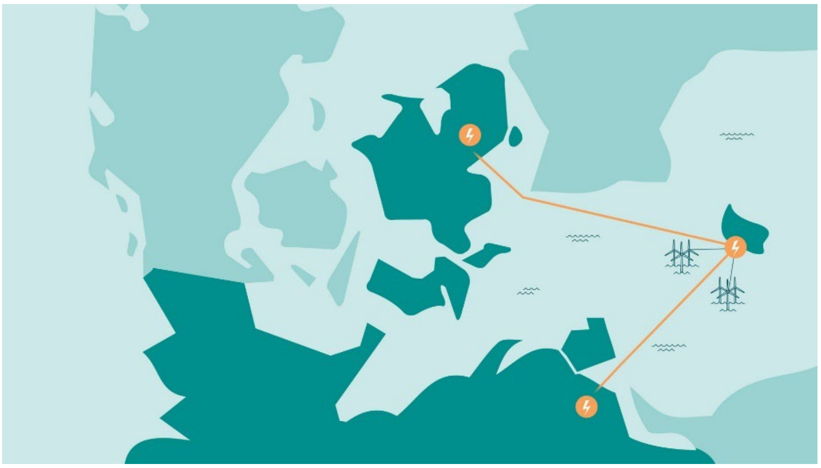

Figure 3-1 Energiø Bornholm (Source: Bornholmenergyisland.eu)

TSO scope

Energinet will be responsible for building and operating the interconnector to DK2, including the related onshore substation and HVDC infrastructure. The investment cost may be covered partly by the offshore wind developer through annual payments (base case in the business case), with a potential option of the State financing this cost (shown as sensitivity analysis in Sub-chapter 3.4.2).

50Hertz will build and operate the interconnector to Germany and take the full cost with no contribution from the offshore wind developer. Congestion revenues from the interconnectors will be shared equally between Energinet and 50Hertz.

Offshore wind developer scope

It is assumed that a single developer, or a consortium of developers, will be responsible for the construction and operation of the offshore wind farm, the associated offshore transmission infrastructure, and the onshore substation and power lines connecting to the Energinet substation. There will likely be an option for 800 MW overplanting, but it is assumed that the developer will build 3.0 GW with no overplanting.

[21] A EUR/DKK exchange rate of 7.46 has been applied in the project.

Support scheme configuration
The cCfD scheme has so far only been approved for upcoming offshore wind tenders in Belgium, making it a new support scheme for both regulators and developers. The main difference compared to the more widely used production-based CfD is that the cCfD's payments between the State and the developer are determined not by the actual production of the offshore wind farm, but by its estimated production capability.

It is beyond the scope of this report to detail how this capability is calculated or how it may influence operational behavior. For simplicity, the cCfD has been modeled almost as a standard production-based CfD, assuming the estimated capable production in the cCfD will on average match the wind farm's anticipated production level without curtailment. The most important difference from the production-based CfD is that the cCfD also protects against volume risk. Therefore, the risk of potential reduced capacity of interconnectors and curtailment due to, e.g., wildlife can be mitigated, depending on the final cCfD design of the project.

Developers will consider optimizing O&M activities to shift generation toward hours with higher power prices under a cCfD, thereby increasing revenue. This is different from a production-based CfD, where developers will try to maximize production, not accounting for differences in power prices when planning O&M. Also, they could strategically adjust maintenance schedules to enhance calculated capability under a cCfD. Further engagement with developers is therefore recommended once the market has had time to fully assess the final cCfD framework.

In contrast, the FIP model provides support as a fixed premium added to the wholesale power price. Unlike a cCfD, it does not offer full price certainty, as project revenues continue to fluctuate with market prices. Nor does it provide any mitigation of volume risk. Developers and financiers therefore regard the FIP model as riskier than a cCfD, though still less risky than full merchant exposure (as discussed in Chapter 1).

For both the cCfD and the FIP in scope of this assessment, the duration is set to 20 years[22], and the support level is indexed based on a standard inflation assumption of 2%. The 20 years are counted from 2037 when the full 3 GW capacity is expected to be online. Until 2037, the power production is expected to ramp up as part of Energinet's test phase, reflecting the current best estimate on market access through interconnectors.

Model and key input parameters
A discounted cash flow model has been developed for calculating the business case for EØB from a developer perspective, in line with the methodology presented in Chapter 2.

The input parameters on costs and production in the model have been obtained from a trusted third-party data provider, and from internal BCG data. The key parameters in the model have been validated through individual discussions with the leading offshore wind developers in Denmark, and their input has been used for calibrating the model assumptions. An aggregated summary of the input parameters can be seen in Figure 3-2.

The assumed 21 MW turbine nameplate capacity for 2034 is considered to be at the upper end of the likely turbine capacity range. An alternative scenario could involve a standardized 15 MW platform, industrialized by OEMs. However, this assumption is not critical for the calculation of

[22] Note that the actual duration could be shorter than 20 years if the budget cap is reached earlier (further discussed in Sub-chapter 3.4.3).

support requirements, given that the current view[23] is that the CapEx level of a larger turbine would be around the same range as a standardized smaller platform.

Learning rates have in the past commonly been applied to estimate CapEx of future projects. Now, uncertainty and cost pessimism have increased, and many developers no longer assume a significant learning rate towards 2034. However, we anticipate the sentiment to generally improve over the coming few years and have therefore applied a CapEx value that is in the lower half of what the market currently expects for 2034. This value was derived not through applying a learning rate, but through an assessment of prevailing market expectations for future CapEx levels.

One additional factor that could influence both future turbine size and CapEx levels is the potential entry of Chinese turbine manufacturers into the European market. Their participation could lead to larger turbine capacities and lower CapEx levels. However, while CapEx might be lower, availability may also be lower for new technology platforms than standardized existing platforms, leading to similar LCOE levels in competition with European OEMs. This effect is yet to be explored and the impact on total LCOE is therefore unclear. Given the significant uncertainty on whether Chinese manufacturers will gain market access, this effect has not been included in the base-case assumptions for this report.

Model parameter	Assumption applied - all prices in 2025 real terms
Configuration	Hybrid park in the new DK3 price zone with export cables to DK2 (1.2 GW) and to Germany (2 GW)
Size of the project	3.0 GW offshore wind lease area capacity awarded to a single developer/consortium
Lifetime	30 years
Year of COD	2035[1] with step wise ramp up of 1 GW/year; all 3 GW in full operations by 2037
Support scheme	Start 2037; 20-year duration
Turbine nameplate capacity	21.0 MW applied
Capacity factor	49.7% (after adjusting for wake effects and availability)
Market access	No market accesses assumed in 2034, 2035 and part of 2036; Regular market access assumed from September 2036[2]
Ancillary services	No additional revenue assumed
Curtailment	No lost revenue assumed under cCfD years (full compensation); 4.24%[3] lost revenue assumed under merchant and FIP years
Power prices	55 EUR/MWh in 2035, decreasing gradually to 42 EUR/MWh in 2047, and assumed to be flat beyond 2047
CapEx	3.5 MEUR/MW (47% wind turbine supply; 15% foundation supply; 20% transmission[4]; 6% contingency; 12% other[5])
CapEx timing	Pre-payments are specified and paid out in first year of construction (2034)
OpEx	0.074 MEUR/MW/yr (incl. grid tariffs and payment to Energinet for the interconnector, excl. balancing costs)
DevEx	0.089 MEUR/MW
AbEx	0.18 MEUR/MW (~5% of CAPEX)
Balancing cost	3 EUR/MWh

Figure 3-2 Key business case model input
1. First power expected end of 2034, and the commercial operation date (COD) is modelled as 2035
2. In line with DEA's assumptions for test years provided at the time of this study
3. Includes 6% contingency
4. Includes supply and installation of onshore- and offshore substations, inter-array cables, export cables and onshore transmission lines, but not potential cost of the interconnector to DK2 (included as annual payment to Energinet and reflected in OpEx)
5. Includes installation of foundations and turbines, construction management and project owner cost

Power prices

Offshore wind capture prices for the new DK3 price zone have been obtained from a trusted third-party power price analytics firm also used by developers. Since the price zone does not

[23] View of internal BCG-experts and in the industry (discussed in meetings with developers).

exist yet, a simulation was run explicitly for calculating the price, given the planned grid configuration. It is assumed that the price zone will be established in 2035.

The forecast period lasts until 2047, and it is assumed for modeling purposes that the power price will remain stable after this year. This simplification is not expected to significantly affect the results, as price forecasts beyond 25 years are highly uncertain and heavily discounted in the business case. Simulations to determine hourly capture prices have been run for 20 different weather years for each year in the forecast period. The result can be seen in Figure 3-3, with the P50 estimate being the one used in the base case, and the P90 and P10 estimates being used for sensitivity analyses.

The P50 estimate implies that the average offshore wind capture price for a year has a 50% probability of being above this value. It can therefore be treated as an average scenario and hence used for the base case. The P90 and P10 estimates similarly imply that the average capture price has a 90% and 10% probability for exceeding this value, respectively.

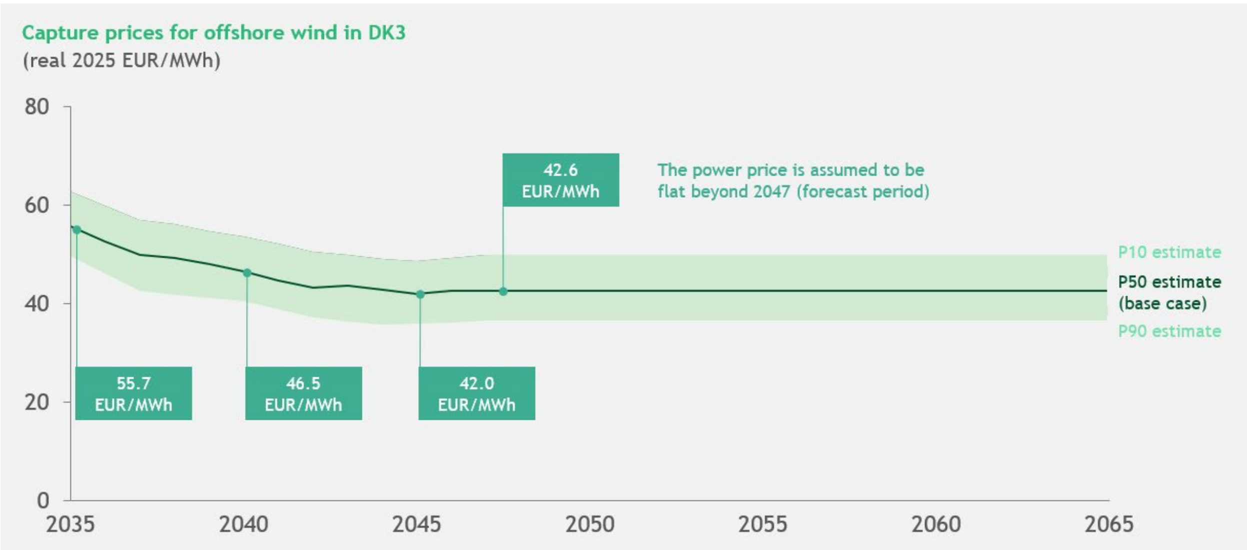

Figure 3-3 Power price estimates applied in the model

3.2 Likely hurdle rate for EØB

3.2.1 Key risk factors for EØB

Beyond the common risk factors that are present in all offshore wind projects, some risk factors have been identified specifically for EØB. Below is a list of these risk factors, and considerations on how developers will likely address them (hurdle rate, contingency, or qualitative). Each of the four risks are individually considered significant enough to deter developers from submitting a bid if not mitigated before the tender.

Size of the project: Awarding a 3.0 GW project to a single developer or consortium is significantly more than most offshore wind projects. Undertaking this project is an investment of 10-15 BnEUR, which adds high financial risk to the developer. Several developers believe that few corporates would be willing to take part in a potential tender if this configuration is kept.

Method to address risk in a developer's business case: Will typically be included as a qualitative consideration, and typically not reflected in hurdle rate or contingency. Therefore, the risk has not been quantified in this report, but rather highlighted as a key risk developers would consider when selecting to pursue the project or not.

Access to market through interconnectors: The reliance on interconnectors for market access introduces a key risk, as the offshore wind asset owner can face curtailment and/or price collapse if the capacity on either interconnector is reduced. The reason could be either onshore grid bottlenecks leading to reduced available capacity, or technical downtime of interconnectors. All offshore wind projects face some risk of grid outages beyond their offshore grid, but this risk is more pronounced for EØB, which depends on both interconnectors operating at close to rated capacity for full power evacuation. This risk lies outside the developer's control, and significant uncompensated downtime could materially impact the business case. It can be noted that the cCfD provides risk mitigation for both prices and production by paying out the support regardless of power delivered, but only over the 20-year duration of the scheme, or until the budget is depleted.

Method to address risk in a developer's business case: Typically included in business cases through assumptions on potential downtime of interconnectors, with a buffer included to account for the uncertainty related to downtime. The risk is therefore not included in the hurdle rate, but could be included as a qualitative consideration on the project in addition to the buffer included in the business case. The impact on revenue for EØB has been assumed to a 4.0% loss[24], when not compensated by a cCfD scheme. In addition, a buffer of 6% more downtime has been included, effectively increasing the total downtime to 4.24%, to account for the uncertainty.

Balancing costs in DK3: Balancing costs are generally viewed as a significant risk for developers. In Northern Europe, recent sharp increases have led to business cases facing balancing costs of up to EUR 10–20 per MWh[25]. A key driver for the increase in balancing costs has been the recent changes to the balancing market, including steps towards automating the mFRR reserve activation, switching to 15-min market resolution, and switching to flow-based market coupling[26]. It is expected that the prices in the balancing market will stabilize at lower levels once the market has had more time to adapt to the new design, but there is high uncertainty related to what price levels to expect in the future. The uncertainty is considered as even more prevalent in the new DK3 price zone, where there is very limited generation/consumption beyond the offshore wind farm. Developers view it as generally challenging to predict balancing costs, and particularly in a new price zone like DK3.

Method to address risk in a developer's business case: Uncertainty around future balancing costs is typically reflected as a contingency in the business case, although difficult to quantify. It is most often not included in the hurdle rate but could be included as a qualitative consideration in addition to the contingency, given the challenges to project future values. Given the recent sharp increase in balancing costs, developers will currently include a substantial contingency. This would lead to an unviable business case, and it is therefore assumed that the projected balancing costs will stabilize at a significantly lower level before a potential tender for EØB. A balancing cost of 3 EUR/MWh has been applied for the base case, and this includes 0.5 EUR/MWh contingency to account for uncertainty[27].

[24] Loss calculated by DEA based on historical data for interconnectors in Denmark.
[25] Experience from BCGs work with offshore wind developers.
[26] See more information about the market design changes here: LINK.
[27] Contingency for balancing costs are typically expressed as EUR/MWh and not a fixed percentage. 3 EUR/MWh includes the contingency (2.5 EUR/MWh base case + 0.5 EUR/MWh contingency = 3 EUR/MWh).

Market access during initial test phase of grid connection: There is uncertainty regarding the available capacity of the electrical infrastructure from Energinet before 2037 due to a 3-year planned test period, which may limit the amount of power that can be delivered to the market during the first three years of operation. This poses a significant risk for developers, who must make highly uncertain assumptions about revenues in this period.

Method to address risk in a developer's business case: In a standard business case, production uncertainty is typically reflected through a buffer in the generation estimates (not in the hurdle rate or as a qualitative consideration). At the current stage, however, this risk is difficult to quantify, as limited information has been provided to the market. It is expected that more detailed guidance will be made available to developers prior to the tender. Consequently, this risk has not been quantified in the present analysis. Instead, the base case applies the DEA's best estimate for power production in the initial years at the time of this study, without any additional buffer for uncertainty related to market access.

Other risk factors for EØB include:

- Uncertainty about the potential crossing of the Nord Stream gas pipeline, potentially affecting wind farm layout.
- Potentially complex stakeholder management and/or delays in construction of the interconnector infrastructure from TSOs.
- Potential curtailment of offshore wind farms due to bats[28].

Method to address risk in a developer's business case: The above risks are mostly driven by uncertainty from the government side. Likely, the majority of these uncertainties can be resolved before the final tender, and none of these risks have been quantified in the business case model. It is important to note that this requires the Government to take concrete actions to mitigate the risks before the tender, as further explained in Sub-chapter 3.3.

Other risks addressed through contingency

Beyond the project-specific risk factors mentioned above, the following risk factors have been included as contingency in the business case:

- Supplier risk
- Delivery risk
- Financial risk (including risk related to exchange rate)

Method to address risk in a developer's business case: The above risks are all captured in the 6% contingency included in the CapEx estimate applied in the base case.

Other risks addressed in the hurdle rate

Risks included in the hurdle rate of the project include:

- Market risk premium
- Technology risk
- Power price risk

Method to address risk in a developer's business case: The following sub-chapter details out how these risks are included.

[28] Can potentially be mitigated in a cCfD scheme, similarly as the risk related to market access through interconnectors.

3.2.2 Calculation of hurdle rate

The method outlined in Chapter 1 has been applied for calculating the hurdle rate of the project from a developer perspective.

A. Defne the support schemes of which to determine the hurdle rate under
Hurdle rates are calculated for the following cases[29]:

- Full merchant power price exposure for the full lifetime of 30 years
- cCfD scheme the first 20 years, and full merchant exposure the last 10 years
- FIP premium the first 20 years, and full merchant exposure the last 10 years

Note that the case with full merchant power price exposure is unlikely to materialize, as the power price forecasts for Denmark are currently at a too low level for developers to be willing to take on a project without state support.

B. Determine likely financing model
As outlined in Chapter 1, it is generally challenging to predict which financing model developers will apply, and it can also vary within each archetype of developers. For EØB, the following assumptions have been applied from FID (assuming all players do balance sheet financing prior to FID):

	Full merchant	**cCfD**	**FIP**
Utilities	Balance sheet	Project	Balance sheet
Oil and gas players	Balance sheet	Project	Balance sheet
Developer funds	Project	Project	Project

Table 3 Assumptions on financing model across developer archetypes (balance sheet financing versus project financing)

It is assumed that the same financing model will be applied from FID until end of project lifetime. This is a simplification, as financing structures can change, but it is considered to have limited impact on the final hurdle rates calculated.

It is assumed that utilities and oil and gas players will rely on balance sheet financing when developing a project with full merchant exposure or under an FIP scheme. The limited revenue certainty in these cases makes project-level debt financing challenging, as banks typically require a high equity share and/or revenue-stabilizing mechanisms such as PPAs, which are challenging to obtain in Denmark. Under a cCfD, it is assumed that the budget cap for support will be sufficient to enable favorable project-finance terms. If the budget cap is lower, a higher share of equity is typically required, and the cost of debt on project level could also be higher. This could make balance sheet financing relatively more attractive for some developers. As mentioned in Chapter 1, the choice of financing model is not viewed as critical when modeling the hurdle rate of an average developer, as hurdle rates tend to converge with different financing models.

Funds typically apply project financing as part of their core business model and are assumed to use this model regardless of support scheme. This will typically imply securing letters of intent on PPAs before going into a tender for the lease area in the case of full merchant exposure or a FIP.

[29] The capacity commissioned in 2035 and 2036 will be exposed to merchant power prices before 2037, and the merchant exposure will at the end of the lifetime be 8 and 9 years for this capacity (10 years for the capacity commissioned in 2037). Note that scenarios with faster depletion of the subsidy budgets have been run and are shown in Sub-chapter 3.4.3.

Utilities:	**Oil and gas players:**	**Developer funds:**
• Ørsted • RWE • Iberdrola • EnBW • SSE	• TotalEnergies • Equinor • Shell • JERA NEX bp	• CIP • Macquarie • Octopus • Centrica

C. Estimate hurdle rates for representative offshore wind developers

The first step for determining hurdle rates of developers is to obtain a representative selection of companies for each archetype developer. The below-listed companies have been selected for the EØB assessment. It is important to note that the estimation has been conducted outside-in, only based on publicly available information[30]. The companies listed are intended as illustrative examples of likely interested parties; their inclusion does not imply that other companies would not pursue the project, nor that the listed ones are certain to participate in a potential tender.

The likely hurdle rates for EØB have been calculated for the three different archetype developers, through the steps as described in Chapter 1. The table below briefly explains the input parameters applied. More thorough explanations on how each of the input parameters can be obtained are shown in Appendix C.

(C1) Calculation of hurdle rate – balance sheet financing

Parameter	Utilities	Oil and gas players	Developer funds
$\frac{D_{BS}}{V_{BS}}$	*Company-specific parameter – calculated for each company separately*		
Tax_{Corp}	*Company-specific parameter – calculated for each company separately*		
r^f	**2.9%** (30-year government bond in Denmark)		
DRP_{BS}	*Company-specific parameter – calculated for each company separately*		
$\frac{E_{BS}}{V_{BS}}$	*Company-specific parameter – calculated for each company separately*		
$\beta_{levered}$	*Company-specific parameter – calculated for each company separately. Adjusted for oil and gas companies to obtain a beta representative for renewable energy development*		
MRP	**4.3%** (market risk premium for Denmark)		
TEC	**1.0 pp.**	**1.3 pp.**	**1.0 pp.**
COM	Full merchant: **3.0 pp** cCfD: **1.0 pp.** FIP: **2.5 pp.**	Full merchant: **2.0 pp** cCfD: **0.8 pp.** FIP: **1.5 pp.**	Full merchant: **3.0 pp** cCfD: **1.0 pp.** FIP: **2.5 pp.**
MAR	**2.0 pp.**	**2.0 pp.**	**2.0 pp.**

Table 4 Assumptions applied for calculating hurdle rate when doing balance sheet financing in the EØB project.

[30] Public information here includes information that is behind a paywall and/or requires subscription, but that everyone can access by paying the required fees.

Technology risk premium (TEC): The technology risk premium (TEC) is assumed to be slightly higher for oil and gas companies than for utilities and funds. This reflects their generally greater risk aversion toward offshore wind technology, driven by more limited experience in developing and operating such projects, and consequently a tendency to apply a higher risk premium. The technology risk premiums applied for EØB are consistent with the magnitude estimated in the assessment of the past 2024 Danish offshore wind tender performed by BCG in the spring of 2025[31]. This is due to the fact that the technical scope for the offshore wind developers is considered similarly complex for EØB as for the projects in scope in that study.

Commercial risk premium: It can also be noted that the commercial risk premium (COM) differs between developers, with oil and gas players generally including a smaller premium than utilities and funds. The reason is that oil and gas companies have a higher comfort with and tolerance for power market exposure, and greater ability to optimize the value of electricity across a broader energy portfolio. Note that the commercial risk premium under a cCfD reflects the first years with merchant power price exposure before the cCfD is incorporated in 2037, and the last 10 years without a support scheme. The risks in these years are included in the lifetime hurdle rate to reflect the riskiness of the full project.

(C1) Calculation of hurdle rate – project financing

Parameter	**Utilities**	**Oil and gas players**	**Developer funds**
$\frac{D_P}{V_P}$	Full merchant: N/A cCfD: **70%** FIP: N/A	Full merchant: N/A cCfD: **70%** FIP: N/A	Full merchant: **55%** cCfD: **70%** FIP: **60%**
Tax_{Market}	**22%** (corporate tax rate in Denmark)		
r^f	**2.9%** (30-year government bond in Denmark)		
DRP_P	Full merchant: N/A cCfD: **2.2%** FIP: N/A	Full merchant: N/A cCfD: **2.2%** FIP: N/A	Full merchant: **3.5%** cCfD: **2.2%** FIP: **3.2%**
$\frac{E_P}{V_P}$	Full merchant: N/A cCfD: **30%** FIP: N/A	Full merchant: N/A cCfD: **30%** FIP: N/A	Full merchant: **45%** cCfD: **30%** FIP: **40%**
$\beta_{levered}$	*Company-specific parameter for the specific project – calculated for each company separately, reflecting the relevant project leverage (see Appendix C)*		
MRP	**4.3%** (market risk premium for Denmark)		
TEC	**1.0 pp.**	**1.3 pp.**	**1.0 pp.**
COM	Full merchant: **3.0 pp.** cCfD: **1.0 pp.** FIP: **2.5 pp.**	Full merchant: **2.0 pp.** cCfD: **0.8 pp.** FIP: **1.5 pp.**	Full merchant: **3.0 pp.** cCfD: **1.0 pp.** FIP: **2.5 pp.**
MAR	**2.0 pp.**	**2.0 pp.**	**2.0 pp.**

[31] See page 10: LINK.

Table 5 Assumptions applied for calculating hurdle rate when performing project financing in the EØB project. Orange color means that the assumptions differ from a balance sheet financing case. Note that N/A are parameters that are not relevant, since assuming balance sheet financing for the relevant archetype company under a certain support scheme.

Some comments can be provided regarding the above assumptions:

Debt- and equity share (D_p and E_p): As previously described, it is assumed that banks will generally require a higher share of equity when doing project financing if having full merchant power price exposure, and under the FIP support scheme. The exact fractions vary from project to project. A 55%/45% debt to equity ratio is considered relevant for the merchant case, a 60%/40% ratio is included for the FIP scheme, and a 70%/30% ratio is applied under a cCfD. No general rule exists for determining the fraction of debt and equity when doing project financing. The above ranges reflect what developers could typically have in their projects, acknowledging that other ratios can also be applicable under each support scheme.

Debt risk premium (DRP_P): Estimating the exact cost of debt on project level is generally challenging, since it will vary from project to project. Compared to a cCfD scheme, it is assumed that banks will offer a higher cost of debt under full merchant exposure and FIP, in addition to requiring a higher share of equity financing.

Margin: It is assumed that all developers apply a margin of 2.0 pp. on top of the cost of capital and project-specific risk premiums, which is a higher margin than what was typically applied in the industry in the past. The increase is due to rising uncertainty in the offshore wind sector, relatively more attractive investment opportunities in other (renewable) energy technologies, and general capital constraints across the industry. In highly competitive tenders for strategically important or high-value assets, this margin may be lower, and in some cases could even become negative. This could particularly be the case where developers prioritize market entry, scale, or long-term positioning over financial returns for the specific project.

When calculating the average hurdle rates for all the reference companies under each archetype developer, the following values are obtained:

	Full merchant	**cCfD**	**FIP**
Utilities	10.7%	8.1%	10.2%
Oil and gas players	10.3%	8.5%	9.8%
Developer funds	10.4%	8.6%	9.9%

Table 6 Calculated hurdle rates for developer archetypes for the EØB project (nominal, unlevered, post-tax)

D. Determine hurdle rate ranges to be tested with the market

As shown in the results above, no substantial differences were identified between the developer archetypes. Consequently, no specific archetype has been selected when determining the hurdle rate, as a 1 pp. range effectively captures all archetypes for each support scheme.

Based on the calculated hurdle rate values across developer types, the following ranges were selected for discussion and validation with the market:

	Full merchant	**cCfD**	**FIP**
Selected hurdle rates	10.0-11.0%	8.0-9.0%	9.5-10.5%

Table 7 Hurdle rate ranges tested with the market (nominal, unlevered, post-tax)

E. Test the hurdle rates with the market and calibrate if needed
The calculated hurdle rate ranges were validated through dialogue with relevant developers. In practice, this involved presenting the above ranges reflecting the current hypothesis for EØB and inviting developers to comment on them. While corporates are generally reluctant to disclose specific hurdle rate figures, they are more open to indicating whether the presented ranges appear too high or too low.

As this analysis forms the basis for determining subsidy payments to developers, there is an inherent conflict of interest, as developers may have an incentive to present the business case as more challenging than it is in reality. However, since Danish offshore wind lease areas and potential support schemes are awarded through competitive tenders, there is little scope for strategic advantage in providing biased input. The industry appears genuinely committed to contributing constructively to the regulatory process and to supporting the realization of offshore wind projects in Denmark. In addition, overstating parameters such as hurdle rates could lead to higher calculated support needs and a lower likelihood of political approval, which would ultimately not benefit developers. Input should always be assessed critically, but the benefits of testing key parameters with developers are considered to outweigh the potential risks.

The hurdle rates presented to developers were generally well aligned with market expectations. However, developers indicated that the hurdle rate for merchant projects is somewhat higher than the initial suggested estimates. Accordingly, this value was adjusted upward to 11.5%, from the initial range of 10.0–11.0%. For the cCfD and FIP cases, the median values of the ranges discussed with developers were adopted.

	Full merchant	cCfD	FIP
Selected hurdle rates	11.5%	8.5%	10.0%

Table 8 Selected hurdle rates for support cap calculations (nominal, unlevered, post-tax)

One could expect that the FIP hurdle rate would lie closer to the full merchant case than to the cCfD case, as the FIP provides no mitigation of volume risk and only limited mitigation of price risk. However, if electricity prices are assumed to rarely fall materially below zero, the premium component effectively establishes a partial price floor, offering some downside protection to developers. Based on discussions with developers, the prevailing view is that the FIP hurdle rate typically falls between the full merchant and cCfD cases. Further description of the takeaways from developer meetings are summarized in Appendix B.

3.3 Logic to calculate the support budget cap for EØB

As outlined in Sub-Chapter 3.2.1, some of the risks for EØB are assumed to be handled prior to the project, while some are reflected in the business case and the hurdle rate. Figure 3-4 summarizes the logic and risk assumptions applied for EØB, and is referred to as *the figure* in this Sub-chapter.

The grey bar on the very left side of the figure illustrates the likely current support requirements given all the uncertainties in the project today. However, many of the uncertainties can be reduced/eliminated, and the ones listed in the second bar in the figure are assumed mitigated before a potential tender. All risks will likely not be fully eliminated, but they can be reduced to a level deemed acceptable by developers.

Further, there are other measures that can be taken to reduce risk for developers and increase chances of multiple bidders in a potential tender, but that do not impact the business case directly. Those include splitting up the lease area in smaller projects and potentially reducing tender fees[32]. The findings on risk mitigation actions related to tender criteria in the conducted study of the 2024 Danish offshore wind tenders are generally applicable to EØB as well[33].

When assuming risk mitigation measures have been taken, the base case support requirements can be calculated. These requirements will be lower in a cCfD scheme than for other support models, given that a cCfD provides both volume- and price risk mitigation, as illustrated in the figure.

To get from the base case support requirements to a support budget cap, the methodology outlined in Chapter 2 is applied. Sensitivity analyses are used for calculating the impact on support requirements of changing selected key input parameters in the business case. Three scenarios are then formulated based on the sensitivities; a Low-support scenario, a Mid-support scenario, and a High-support scenario, shown in the blue box in the middle of the figure. The support budget cap is determined as the support requirements in the Mid-support scenario, reflecting slightly more conservative assumptions than in the base case to provide a buffer between the most likely support requirements and the budget cap.

The figure illustrates an additional step beyond this – namely, potential levers to de-risk and strengthen the EØB business case, thereby reducing the required level of state support. The levers shown represent measures that the government could consider implementing. They are not examined in detail in this report, but could be a next step to increase the likelihood of realizing EØB.

[32] Will depend on the proposed level of fees not yet announced for EØB.
[33] Source: LINK

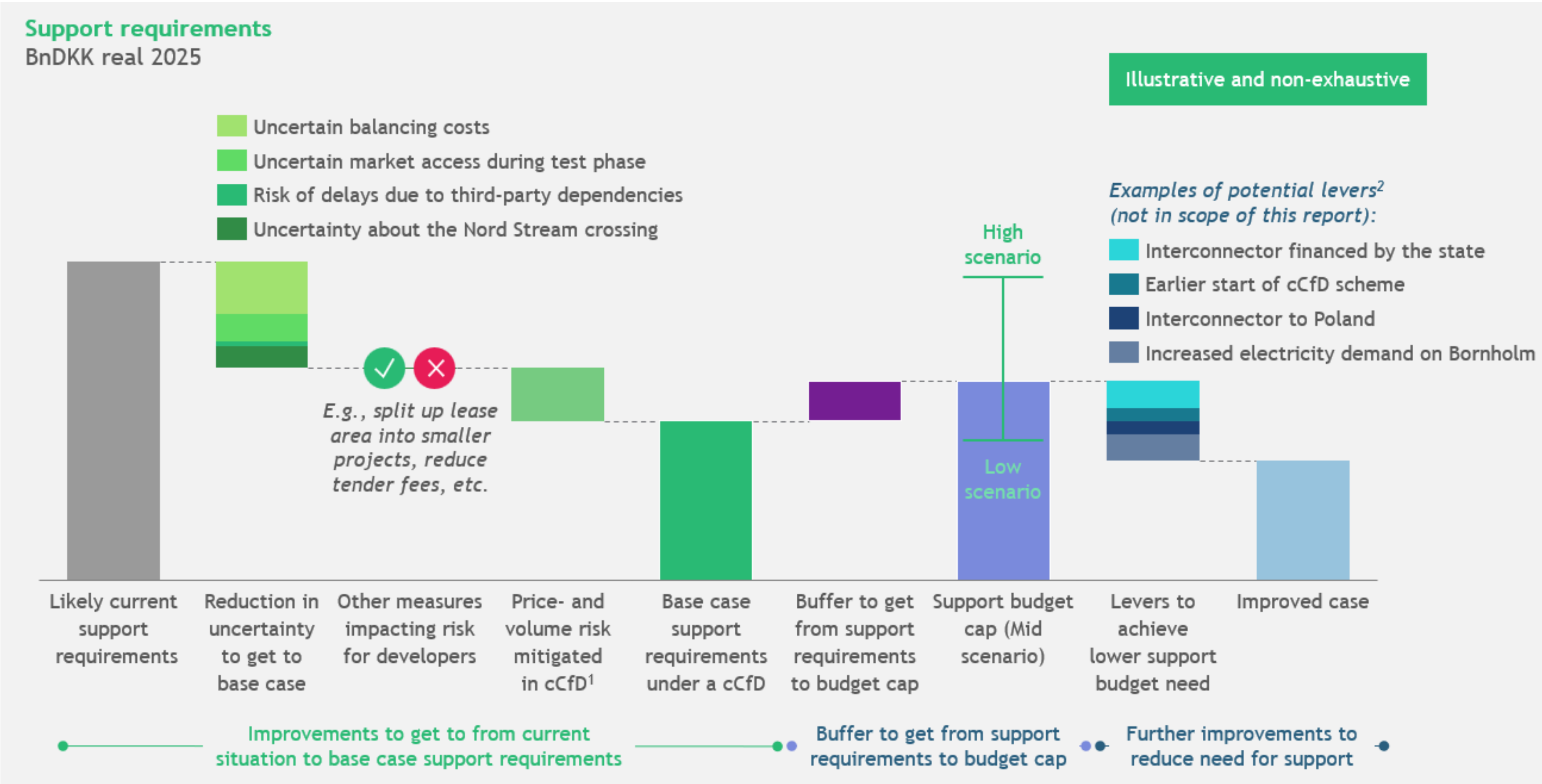

Figure 3-4 Support budget cap logic applied for EØB
1. Mitigates power price risk, risk of limited interconnector capacity and potentially curtailment due to bats
2. Only illustrative examples (not recommendations for levers)

3.4 Likely support budget cap for EØB

To assess the level of state support required for developers to achieve viable business cases, the methodology described in Chapter 2 is applied. The analysis determines the required strike price under a cCfD scheme and the necessary premium under a FIP model that would make the project's IRR equal the required hurdle rate. The base case support requirements are first presented (3.4.1), followed by sensitivity analyses (3.4.2), and finally the calculation of the support budget cap (3.4.3).

Note that IRR and hurdle rates are always stated as the nominal, unlevered, post-tax values. Support requirements / support budget caps are shown in real 2025 DKK values, while strike price/ power price premium values are stated as real 2025 EUR values, with real 2025 DKK values in parentheses.

3.4.1 Base case results for support requirements

The base-case business model is built on the key input parameters described in Sub-chapter 3.1, and the results are shown in Figure 3-5. The model first estimates the business case for a developer without any support scheme. It then calculates the strike price under a cCfD and the premium under an FIP required to achieve the target hurdle rates. Based on these results, the total state support – defined as the undiscounted sum of all subsidy payments over the 20-year support period – can be determined.

Here, it is assumed that the support will be paid out over the full 20-year duration of the scheme. The scenarios shown in Sub-Chapter 3.4.3 explain the difference in support requirements if assuming that the support can be paid out over a shorter period of time.

Full merchant: Under full merchant power price exposure (without any state support), the IRR of the project is estimated at -0.9%, substantially below the 11.5 % required hurdle rate.

CfD: To obtain the revenue required to achieve an IRR equal to the 8.5% hurdle rate, developers would require a strike price of 115 EUR/MWh (85.8 øre/kWh). This corresponds to a total undiscounted support requirement of approximately 139 BnDKK[34] over 20 years.

FIP: To reach a hurdle rate of 10.0%, the required feed-in premium is +92 EUR/MWh (+68.6 øre/kWh), added on top of the merchant power price. This translates to a total undiscounted support requirement of approximately 172 BnDKK over 20 years.

More information on the results, and what the differences are in assumptions between the results shown below and the results obtained in the base case of DEA is shown in Appendix A.

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[34] Given the assumed power prices. If power prices are higher, the 115 EUR/MWh will translate to a lower support requirement, and vice versa.

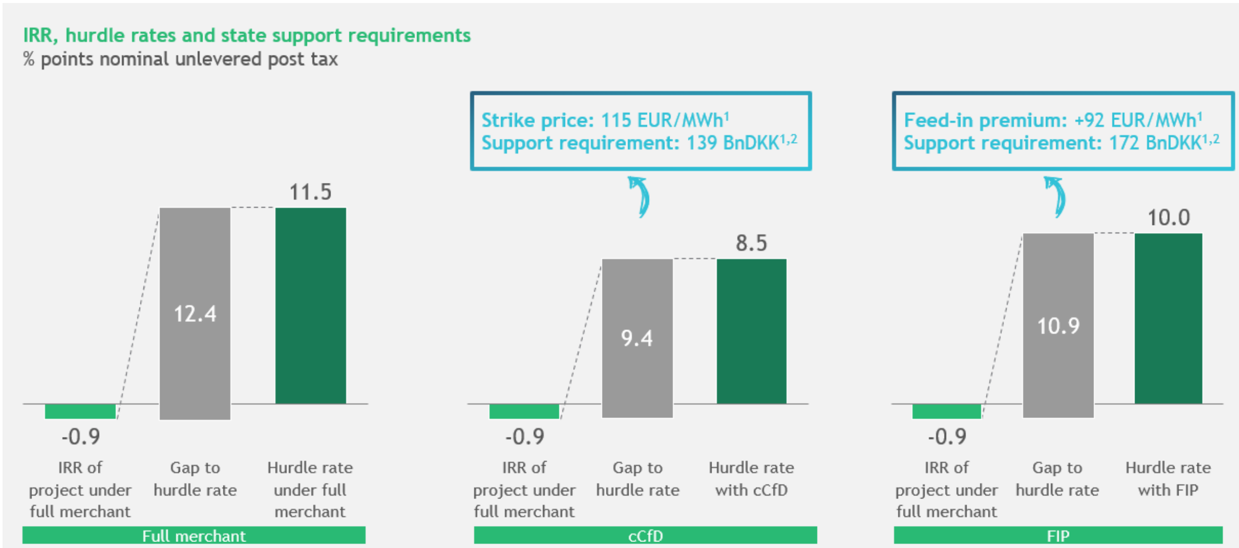

Figure 3-5 State subsidy requirement in the base case. Note that hurdle rates are always shown in nominal terms, while the strike price and support requirements are shown in real 2025 terms.
1. Shows the expected strike price and feed-in premium, as well as the corresponding support requirement, given a 20-year support scheme under the base case capture price assumptions

A business case model like the one applied in this report is highly sensitive to a number of parameters. The base case represents the most likely case, but sensitivity analyses should always be conducted to map out the likely option space for support.

3.4.2 Sensitivity analyses

The sensitivity analyses reflect both that key business case assumptions can differ between developers, and the uncertainty associated with how assumptions can change over the coming years. For simplicity, the sensitivity analyses have been conducted only for the cCfD support scheme, as it is considered the most relevant, potential support model.

Below is a description of each of the sensitivities included in the analysis. The sensitivity values have been chosen to represent the spread that different developers will see in the industry today, and to capture the uncertainty of how the industry will develop. The top and bottom estimates reflect the likely outliers of ranges developers can end up having in their business cases when going into a potential tender for the EØB lease area:

- **CapEx:** +1.0 MEUR/MW and -0.5 MEUR/MW change in total CapEx included. This range is considered to include the span of values developers will typically have in their business cases.
- **Hurdle rate:** ±1 pp. change in the assumed hurdle rate included. Most developers are likely to apply a value within this range, while some might have different assumptions in their business case models.
- **Capture prices:** The previously mentioned P90 estimate applied for the high sensitivity, and P10 estimate applied for the low sensitivity.
- **Balancing costs:** +7 EUR/MWh and -1 EUR/MWh in balancing costs included. The high sensitivity represents a stabilization of prices at a higher level than in the past. The low sensitivity represents returning to "the old world" with lower balancing costs.

- **Power production:** ±2.5 pp. in capacity factor included. Developers have different assumptions about production, based on, e.g., external wake effects from surrounding offshore wind farms and choice of turbines, which is reflected in this sensitivity.
- **Interconnector cost:** Scenario with no annual payment required from the developer to Energinet for the investment cost of the interconnector between Bornholm and Zealand included.
- **Construction delay:** One year delay in construction and commercial operations of the whole project including interconnectors, with the likely fees associated with such a delay included[35]. It is assumed that the CapEx will remain constant, and the business case impact will only come from the delay and the fees.
- **Support scheme timing:** Earlier start of the cCfD support scheme from 2035 instead of 2037 as in the base case. Here, the support scheme is only assumed to be applicable for the capacity that has been commissioned, in line with the 1 GW/year commissioning plan.
- **Market access in test years:** Full power production from COD for each step of the wind farm commissioning (instead of the 3-year test phase with reduced market access as in the base case) included as low sensitivity. High sensitivity assumes no market access before 2037.

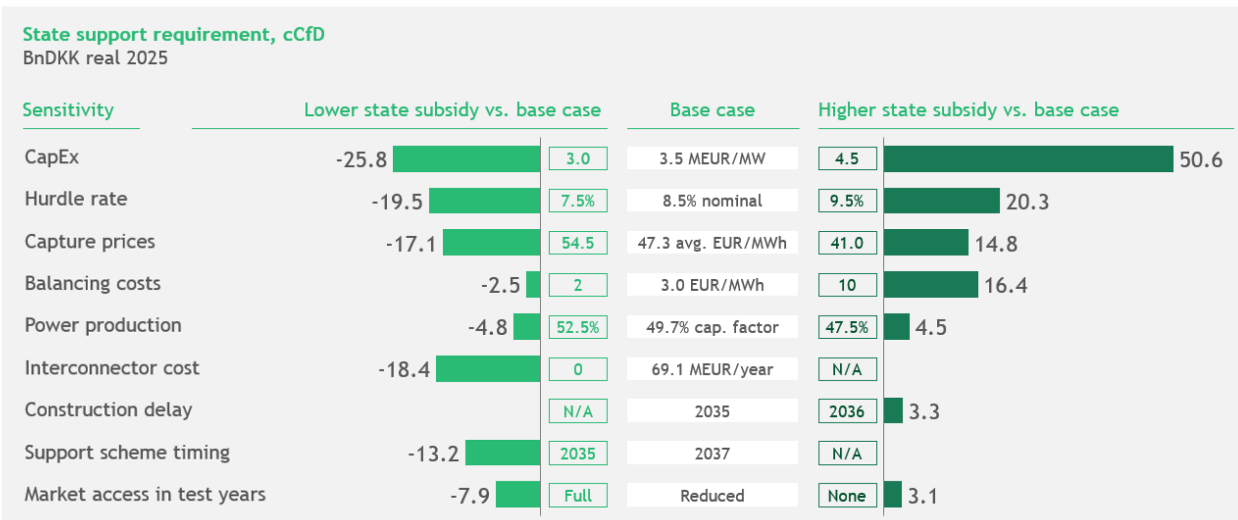

Figure 3-6 Sensitivity analyses

As seen from the sensitivity analyses in Figure 3-6, there are 6 different parameters that the business case is highly sensitive to, resulting in double-digit impact on support requirements.

First, the assumption on CapEx is highly important, with a -0.5 MEUR/MW change from the base case, the support requirements are reduced by roughly 26 BnDKK, while it increases by ~51 BnDKK if assuming an increase of +1.0 MEUR/MW. The two CapEx values are considered outliers in the likely range developers are expecting.

Second, the hurdle rate assumption is sensitive, with changes of around 19-20 BnDKK in support requirements if adjusting the assumption by only 1.0 pp.

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[35] The fees reflect the same structure as in the 3 GW Danish offshore wind tender launched in 2024, but the magnitude is halved based on the communicated changes for the upcoming 3 GW re-tender.

Third, avoiding the interconnector cost could reduce the support requirements by around 18 BnDKK. Note that the high absolute support requirement relative to the estimated total investment cost of the interconnector is explained by the structure of the cCfD scheme. The payments under the scheme are spread over 20 years, and the calculated requirement represents the non-discounted sum of total support.

Fourth, the model is highly sensitive to power price assumptions. The support requirement increases by around 15 BnDKK when applying the P90 price estimate and decreases by about 17 BnDKK under the P10 estimate.

Fifth, the timing of the support scheme highly impacts the support requirements, with a reduction of about 13 BnDKK in support requirements if being in place as soon as capacity comes online. This is an important finding from a government perspective, as it can inform how to best design a potential cCfD scheme. Further consideration on impact from timing of subsidy payments are included in Sub-chapter 3.4.3.

Sixth, the potential increase in balancing costs could have substantial impact on the business case (+16 BnDKK), while there is less room for lower support requirements due to lower-than-expected balancing costs (-2.5 BnDKK).

The relationship between input assumptions and the resulting support requirement is non-linear. For instance, increasing the hurdle rate by 1.0 pp. does not have the same absolute effect on required support as reducing it by 1.0 pp. This is because the internal rate of return (IRR) is a non-linear function of cash flows, and both the magnitude and timing of these cash flows influence how sensitive the results are to parameter changes. Consequently, adjustments to key inputs lead to asymmetrical changes in the calculated support requirements to achieve the required hurdle rate.

3.4.3 Support budget cap calculations

The above results show the support requirements in the base case, and how it would change under the sensitivity analyses. To determine the support budget cap, a decision must be made by the Government on how much buffer should be included between the required magnitude of support and the budget cap. If wanting a higher likelihood of realizing the project, a higher buffer should be included and vice versa.

Three scenarios have been included to determine support budget caps with different degrees of certainty for the project to be realized. The more conservative (negative) the assumptions applied in the scenarios are, the higher the required level of support will be when setting the budget cap equal to the requirements in each scenario.

The three scenarios are shown in Figure 3-7, with the Mid-support scenario as the suggested one for determining the support budget cap. This represents a scenario where the base case assumptions are deemed realistic, but where a buffer is added for the most important parameters, making them slightly more conservative. This is consistent with the methodology described in Chapter 2.

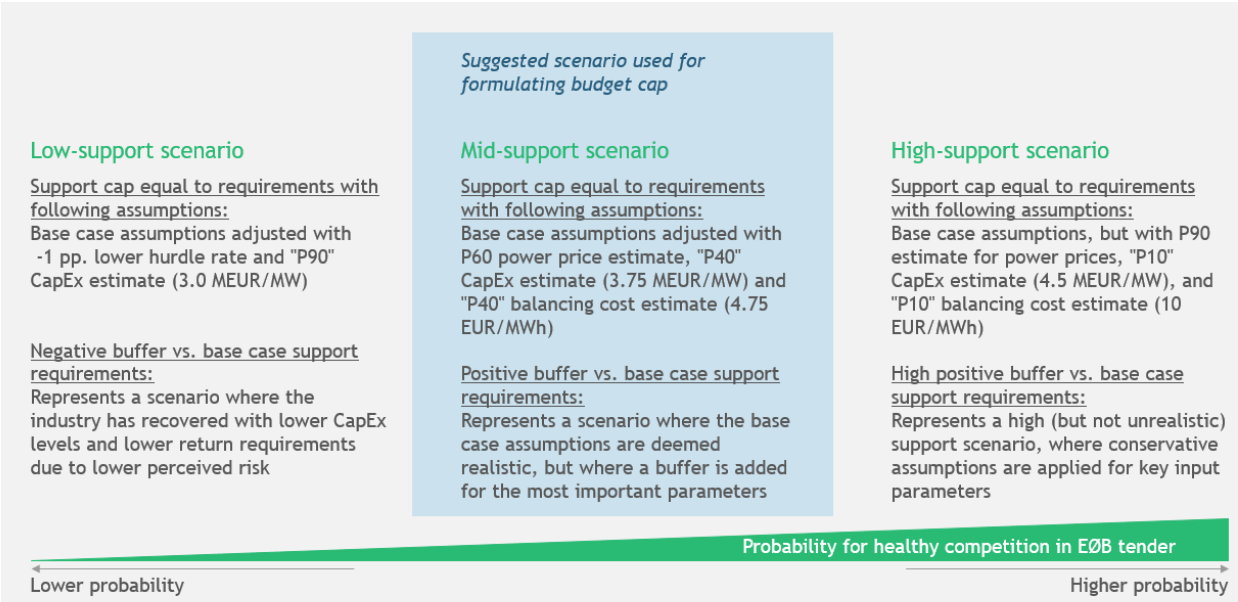

Figure 3-7 Scenarios for determining the support budget cap

The support budget cap in each scenario is shown in Figure 3-8. The bars in the diagram show the accumulated undiscounted state support required when assuming payout of the support over 20 years. This will typically materialize if there is a reserve price set in the cCfD tender corresponding to the budget cap.

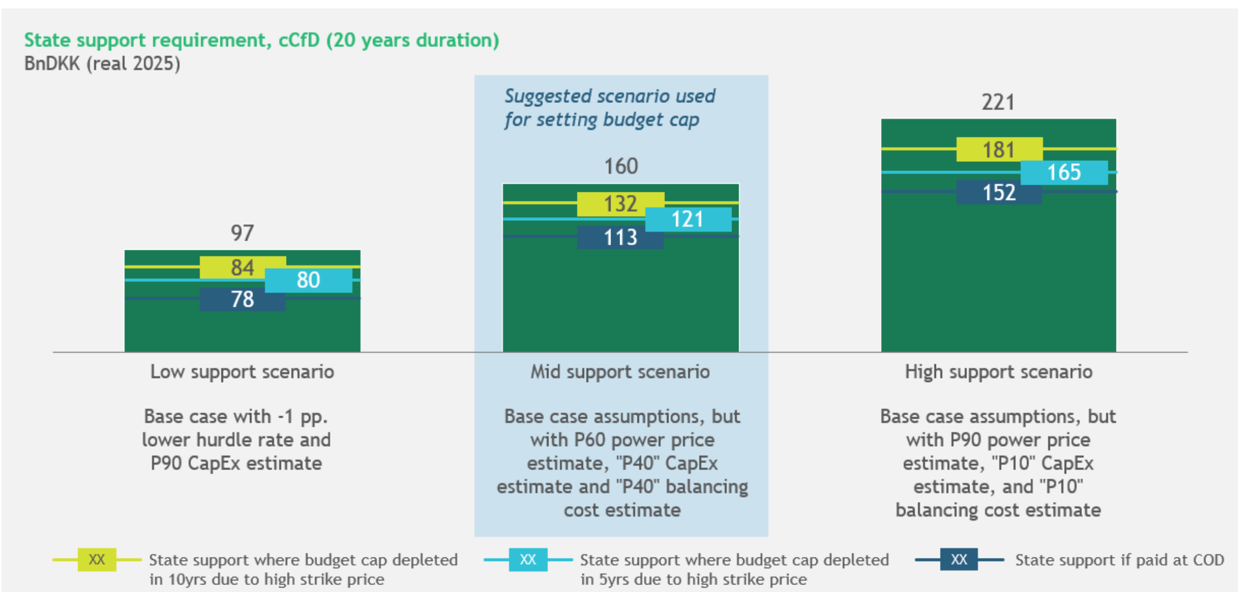

Figure 3-8 State subsidy requirement in the different scenarios

The yellow lines show the support budget cap when assuming that the budget will be paid out over only 10 years. The light blue horizontal lines similarly show the budget if paying out the support over 5 years. In these cases, the subsidy need will be lower, since it is less discounted in the developer's business case. However, the developer will demand a higher total return, since a lower share of the revenue is de-risked. Therefore, a higher hurdle rate reflecting the 10 and 15 additional years of merchant power price exposure after depletion of the budget is applied for determining the support requirement in these cases.

The dark blue lines represent the support budget cap if the whole support budget is paid out at COD. If the support budget cap does not allow a viable business case over a 20-year period, developers may respond by bidding very high cCfD prices. This would quickly deplete the available budget, effectively moving the scheme closer to an investment-support model.

The analyses show that shorter support-payment durations are associated with lower support requirements. This suggests that the benefit of receiving payments earlier outweighs the impact of higher hurdle rates arising from increased merchant exposure when a smaller share of revenues is de-risked. In practice, the relative importance of these effects will vary across developers. Some developers operate under internal constraints that limit acceptable merchant exposure, making shorter support-payment durations unfeasible. Others may consider the additional commercial risk manageable and therefore prefer earlier disbursement of support. The results shown in Figure 3-8 reflect the likely perspective of an average developer.

Assuming the State intends to distribute the support budget evenly over 20 years and sets a reserve price in the cCfD tender to ensure this, the required budget cap would be 160 BnDKK, consistent with the Mid-support scenario assumptions. If, instead, a faster payout is permitted, the cap could be reduced to around 113 bn DKK if paid at COD.

It is important to be aware that the support budget caps are all shown in non-discounted terms. The present value of the Mid-support scenario budget cap at FID from a developer perspective is 73 BnDKK – considerably less than the 160 BnDKK non-discounted value.

Another factor to consider is that the support budget caps are likely overestimated, as they assume that corporate tax is paid in full by the project, as described in Chapter 2. In practice, developers are expected to apply tax optimization strategies, meaning that the actual support required is likely lower.

In a scenario where no taxes are paid, the Mid-support budget cap would decrease from 160 to 132 BnDKK (59 BnDKK present value at FID). In reality, developers will pay some level of tax, and the support cap could be adjusted downward based on expected effective tax rates defined by tax specialists. Alternatively, the overestimation resulting from not accounting for tax optimization can be viewed as part of the buffer applied when moving from the calculated support requirements to the final support budget cap.

4 Discussions and conclusion

This report presents a methodology for estimating offshore wind developers' hurdle rates and the corresponding state support budget cap required to increase likelihood of project realization. While the approach is comprehensive, the most important to prioritize if having limited time/resources, is validating the few key input parameters – hurdle rates, CapEx, offshore wind capture prices, and balancing costs – with the market. Market validation of these parameters should take precedence over detailed bottom-up estimation, as developers' assumptions about future values can shift rapidly.

The offshore wind market has undergone a challenging period in the past 2-3 years. A lethal combination of supply chain bottlenecks and significant CapEx increases, higher interest rates and financing costs, geopolitical uncertainty, delayed uptick in power demand and lower prices as result, and more volatile power prices and higher balancing costs have made the business case for offshore wind difficult across all markets. Developers have revised their strategies, narrowed their geographical focus, trimmed their portfolios, and worked relentlessly on cost reductions to meet these challenges. We now observe an industry-wide “value over volume” mantra and developers that are a lot more cautious and risk averse than before the crisis.

In Denmark, no clear signs of market improvements have been observed since the 2024 tender analysis performed by BCG. While the underlying cost drivers have started to slightly improve (component costs have come down, apart from turbines, and interest rates are improving), there is a more negative sentiment in the market. This leads to similar levels of CapEx, cost of capital, and revenue uncertainty as in the 2024 tender among developers. This is also the case for EØB as developers currently don’t factor learning rates into their business cases for future tenders. Not everything is dark though. In Europe and some Asian markets, governments have shown a strong willingness to support the industry due to its’ critical importance for energy resilience, industrial competitiveness, decarbonization, and job creation. Developers have used the crisis to rightsize their organizations and slim their cost structure, and they are better equipped than ever to deliver offshore wind projects once the industry recovers. There is a healthier balance in the supply chain, and OEMs stand stronger and similarly better equipped to deliver technology and cost improvements going forward. On the demand side, hydrogen is delayed but data centers are booming. Electrification of heat and industrial production increasingly make sense from an economic point of view (i.e., not driven primarily by decarbonization). Demand is still delayed but will start to increase rapidly in the coming years. Without predicting a specific recovery point for the industry, we see signals of improvement and anticipate a stronger industry emerging within the coming few years.

However, the business case for EØB is currently challenging. Without state support, the project’s IRR is estimated at –0.9%, far below the required 11.5% merchant hurdle rate, confirming that a subsidy mechanism is essential for viability. Under a cCfD, a strike price of 115 EUR/MWh would be required to meet the 8.5% hurdle rate, corresponding to an estimated 139 BnDKK in total support requirement (base case). Under an FIP scheme, developers would require +92 EUR/MWh on top of the capture price, translating to an estimated 172 BnDKK in total support. These estimates are non-discounted total support in real 2025 terms, assuming payout over the full 20-year scheme duration.

To make the realization of the EØB project likely, the state support cap under a cCfD is estimated at 160 BnDKK if paid out over 20 years (Mid). In an optimistic case where the industry recovers, the support cap would be 97 BnDKK (Low), whereas it would be 221 BnDKK in a more negative case (High). If assuming that the budget in the Mid scenario is paid out in less than 20 years, the support budget cap can be lowered to 132 BnDKK (10 years), or even as low as 113 BnDKK in an extreme case where the budget is paid in full at the date of commissioning.

The values presented assume corporate taxes are paid in full, which is likely not the case due to tax optimization performed by developers. If assuming no taxes are paid from the project, the state support cap under a cCfD is estimated to 132 BnDKK if paid out over 20 years (Mid).

Aside from the likely overestimation of tax payments, the base case assumptions are viewed as representative of a typical developer perspective. The buffer between the calculated support requirements and the budget cap – arising from adjustments to key parameters in the Mid-support scenario – is considered adequate, particularly when accounting for the additional buffer created by the conservative treatment of tax payments.

In summary, the required support budget cap to make the realization of the EØB project likely is somewhere between 132 BnDKK and 160 BnDKK dependent on tax assumptions for the developer in the Mid-case. However, given the sensitivity of the business case, the budget cap ranges from 97 BnDKK (Low) to 221 BnDKK (High) depending on the most critical market beliefs and input assumptions[36].

It is outside the scope of this project to assess potential levers to decrease the required state support, and the corresponding budget cap. Nevertheless, it should be mentioned that there are measures that could be considered by the government to improve the business case of developers and hence reduce subsidy requirements. Examples include full state financing for the interconnector to DK2 and earlier start of the support scheme. As an example, the sensitivity analysis shows that full state financing of the interconnector will lower the support requirement by 18.4 BnDKK. This would lower the required support budget cap to approximately 114 BnDKK if no corporate taxes are paid from the project and approximately 142 BnDKK with full taxes.

[36] Assuming taxes are paid in full.