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Results of the cost-benefit analysis of establishing offshore wind in the form of an energy island in the Baltic Sea

Danish Energy Agency

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Danish summary

Et flertal i Folketinget indgik den 22. juni 2020 *Klimaaftale for energi og industri mv. 2020* (KEI20). Aftalen indebærer bl.a. etablering af to energiøer i hhv. Nordsøen og Østersøen med i alt 5 GW havvind tilkoblet. Efterfølgende har der været en række tillægsaftaler (oplistet nedenfor) om rammerne for etableringen af energiøerne. I de politiske aftaler om energiøerne er det en betingelse, at øerne skal være rentable. Nærværende rapport vedrører rentabiliteten for Energiø Bornholm (3 GW), som skal etableres i Østersøen. Rentabiliteten afspejles både fra et samfundsøkonomisk og projektøkonomisk perspektiv.

Aftaler for energiøer

- *Tillæg til klimaaftale om energi og industri af 22. juni 2020 vedr. Ejerskab og konstruktion af energiøer mv.* af 4. februar 2021.
- *Udbudsforberedende delaftale om langsigtede rammer for udbud og ejerskab af energiøen i Nordsøen* af 1. september 2021.
- *Tillægsaftale om Energiø Bornholm* 2022 af 29. august 2022.
- *Udbudsforberedende delaftale II om udbud af energiøen i Nordsøen* af 3. oktober 2022.
- *Tillægsaftale om udbudsrammer for 6 GW havvind og Energiø Bornholm* af 30. maj 2023.

Usikkerheder i rentabilitetsberegninger

Det bemærkes, at Energistyrelsens rentabilitetsberegninger er behæftet med betydelig usikkerhed. De varierer markant afhængig af de antagelser og metoder, som lægges til grund for beregningerne. Det skyldes, at rentabiliteten af Energiø Bornholm i høj grad afhænger af udviklingen i det fremtidige europæiske og danske energisystem over en meget lang periode. Derfor er det kun muligt at sandsynliggøre rentabiliteten i givne scenarier, og denne kunne ændre sig betydeligt over projektets levetid, som vil strække sig væsentligt om på den anden side af 2050.

Resultaterne af rentabilitetsberegningerne præsenteres derfor med forskellige spænd i forhold til udviklingen i det fremtidige europæiske energisystem. Det er afgørende at understrege, at det ikke er muligt at vurdere, hvilket scenarie som er mest retvisende, men overordnet viser analysens centrale estimater, at det ud fra de anvendte samfunds- og projektøkonomiske scenarier ikke vurderes rentabelt at etablere Energiø Bornholm med en kapacitet på 3 GW havvind i 2030. Dette blev præsenteret for forligskredsen bag aftalen i foråret 2023, hvor der på den baggrund blev indgået en politisk aftale om fastlæggelse af støtteloft for Energiø Bornholm. Samtidig viser analysen, at en højere brintpris og deraf afledt elpris samt en omfattende grøn omstilling i Europa vil kunne have afgørende positive effekter for rentabiliteten for Energiø Bornholm.

Politisk aftale om fastlæggelse af støtteloft (30. maj 2023)
Rapportens resultater er blevet præsenteret tidligere for aftalepartierne ifm. *Tillægsaftalen* af 30. maj 2023, hvor det blev besluttet at fastsætte et støtteloft på 17,6 mia. kr. (faste priser) for Energiø Bornholm. Dette beløb svarer til det forventede udgiftsniveau, som systemoperatøren forventes at overvælte på havvindsopstilleren samt udgifter vedrørende øgede bæredygtighedskrav besluttet ved samme aftale.

Opsummering af rentabiliteten for Energiø Bornholm
Hvis man anvender et delvist målkonsistent scenarie (c) for udviklingen i det danske og europæiske energimarked samt en add-on investeringsmetode[1], kan rentabilitetsbetingelsen ikke garanteres opfyldt. Baseret på disse antagelser og afhængigt af den anvendte antagelse om den fremtidige brintpris varierer den estimerede samfundsøkonomi på baggrund af den gennemførte cost-benefit-analyse fra et underskud på -16 mia. kr. til et overskud på 4 mia. kr. (nutidsværdi). Den samfundsøkonomiske projektøkonomi varierer fra et underskud på -20 mia. kr. til et resultat på 0 (nutidsværdi), hvilket svarer til et forventet støttebehov på mellem 5 og 25 mia. kr. (nutidsværdi) eller 10 og 48 mia mia. kr. (faste priser), *jf. opsummerende tabel*. Hvis Energiø Bornolm modtager EU-støtte, vil støttebehovet alt andet lige være lavere.

Opsummerende tabel

Opsummering af rentabilitet

Mia. DKK (2022 priser)	Samfundsøkonomisk projektøkonomi	Samfundsøkonomi	Projektøkonomi (Negativt tal = Støttebehov)		Politisk besluttet støtteloft
	Nutidsværdi	Nutidsværdi	Nutidsværdi	Faste priser	Faste priser
Frozen policy	-12	-17	-30,0	-58,0	
Ligevægtskorrigeret	(-21; 0)	(-16; 4)	(-25; -5)	(-48; -10)	
Delvist målkonsistent	**(-20; 0)**	**(-16; 4)**	**(-25; -5)**	**(-48; -10)**	**17,6**
Målopfyldelse	(-11; 10)	(-12; 8)	(-15; 5)	(-29; 10)	

Anm.: De rapporterede tal reflekterer et spænd i den fremtidige brintpris, og elprisen afledt deraf, samt forskellige udfald af den grønne omstilling i Europa, fra Frozen policy til Målopfyldelse. Der anvendes en add-on investeringsmetode. Resultaterne for samfundsøkonomien samt den samfundsøkonomiske projektøkonomi angives i nutidsværdi og forudsætter ingen værdi af overplanting. Det estimerede støttebehov angives i både nutidsværdi og faste priser og antager 800 MW overplanting. Eventuel EU-finansiering er ikke indeholdt i tallene.

Kilde: Energistyrelsen (2023)

For at imødekomme de væsentligste identificerede usikkerheder, foretages der en række følsomhedsanalyser, herunder følsomheder af forskellige scenarier for CAPEX, afkastkrav og fremskrivning af elpriser, der viser, hvor robuste resultaterne er

[1] Økonomien i et scenarie, hvor projektet antages realiseret, sammenlignes med økonomien i et scenarie, hvor projektet ikke realiseres.

ved ændringer i de antagelser, der ligger til grund for beregningerne. Dertil er der belyst en række potentielle projektøkonomiske gevinster, såsom indtægter fra overplanting samt en række potentielle samfundsmæssige gevinster såsom øget dansk og europæisk forsyningssikkerhed, CO_2-reduktion og at Danmark bliver nettoeksportør af grøn energi.

Konklusionerne er behæftet med usikkerheder, særligt grundet usikkerhed i estimeringen af kapitaludgifterne (i det følgende ”CAPEX”) og de fremtidige elpriser, da den endelige investeringsbeslutning (FID) først finder sted flere år ude i fremtiden. Der er således forventning om forskydninger på både efterspørgsels- og udbudssiden, hvorfor disse er behæftet med betydelig usikkerhed. Dette gælder bl.a. betydelige forskydninger som følge af elektrificering af transportsektoren samt fremstillingen af grønne brændstoffer ved Power-to-X (i det følgende ”PtX”). Hertil kommer, at Energiø-konceptet i sig selv indebærer udbygning af havvind i hidtidig uset skala.

Executive summary

On June 22nd 2020, a majority in the Danish parliament voted for a climate agreement on energy and industry "*Klimaaftalen for Energi og Industri af 22. juni 2020*" (KEI20). Among other things, the agreement includes the establishment of two energy islands in the North Sea and the Baltic Sea with an initial total capacity of 5 GW of offshore wind power connected. Subsequently, there have been several supplementary agreements (listed below) regarding the framework for the establishment of these energy islands. The political agreements on the energy islands stipulate that they must be profitable. This report concerns the profitability of the Energy Island in the Baltic Sea (3 GW). Profitability is assessed from both a project-economic and socio-economic perspective.

Supplementary agreement for the Energy Islands

- *Tillæg til klimaaftale om energi og industri af 22. juni 2020 vedr. Ejerskab og konstruktion af energiøer mv.* af 4. februar 2021.
- *Udbudsforberedende delaftale om langsigtede rammer for udbud og ejerskab af energiøen i Nordsøen* af 1. september 2021.
- *Tillægsaftale om Energiø Bornholm* 2022 af 29. august 2022.
- *Udbudsforberedende delaftale II om udbud af energiøen i Nordsøen* af 3. oktober 2022.
- *Tillægsaftale om udbudsrammer for 6 GW havvind og Energiø Bornholm* af 30. maj 2023.

Uncertainties in Profitability Calculations:

Notably, the profitability calculations by the Danish Energy Agency are subject to a high degree of uncertainty. They vary considerably depending on the assumptions and methods used in the calculations. This is because the profitability of the Energy Island in the Baltic Sea largely depends on the future development of the European and Danish energy systems. Therefore, it is only possible to estimate the profitability of the project in certain scenarios, which will be subject to significant changes over the long lifespan of the project, extending well into the second half of the 21st century.

Consequently, the results of the profitability calculations in the report are presented with different intervals based on the development of the future European energy system. It is crucial to emphasize that it is not possible to determine which scenario is most accurate. However, the central estimates of the analyses indicate that it is not, from neither a societal nor a project-economic perspective, considered profitable to establish the Energy Island in the Baltic Sea with a capacity of 3 GW offshore wind power by 2030. This was also presented to the parties involved in the agreement (*Tillægsaftalen* af 30. maj 2023), in which the subsidy limit for the Energy Island in the Baltic Sea was decided. At the same time, the analysis shows that a higher price on hydrogen and thus electricity prices, along with an extensive green transformation in Europe, could have significant positive effects on the profitability of the Energy Island in the Baltic Sea.

Political Agreement Setting subsidy limit (May 30, 2023):
The results of the report were previously presented to the parties involved in the supplementary political agreement (*Tillægsaftalen* af 30. maj 2023), where it was decided to set a subsidy limit at 17.6 billion DKK (fixed prices) for the Energy Island in the Baltic Sea. This corresponds to the expected expenditure, which is assumed passed on from the system operator to the offshore wind developer, and the assumed costs from the increased sustainability requirements decided upon in the same agreement.

Profitability results of the Energy Island in the Baltic Sea
When applying the partially target consistent approach (c) and the add-on investment method, the profitability requirement cannot be guaranteed to be fulfilled. When conducting a CBA based on these assumptions and applying different assumptions on the future price of hydrogen, the results show a socio-economic result varying from a loss of -16 billion DKK to a profit of 4 billion DKK (net present value). The socio-economic project-economic result varies from a loss of -20 billion DKK to 0 DKK (net present value), which corresponds to an estimated need for a support scheme of between 5 and 25 billion DKK in net present value or 10 to 48 billion DKK in fixed prices, *cf. Summarising table*. If the Energy Island in the Baltic Sea receives the expected EU funding, the need for support will be reduced accordingly.

Summarising table

The summarised profitability calculations

DKKbn (2022 prices)	Social-economic project econom-ics	Social-economic profitability	Project economics (Negative number = need for subsidy)		Politically agreed subsidy limit
	NPV	NPV	NPV	Fixed prices	Fixed prices
Frozen policy	-12	-17	-30,0	-58,0	
Lower estimate for green transition	(-21; 0)	(-16; 4)	(-25; -5)	(-48; -10)	
Partially target consistent	**(-20; 0)**	**(-16; 4)**	**(-25; -5)**	**(-48; -10)**	**17,6**
Target consistent	(-11; 10)	(-12; 8)	(-15; 5)	(-29; 10)	

Note: The reported numbers reflects a span for the future hydrogen price, and the electricity price derived from that, as well as different possible green transitions in Europa, from a Frozen policy scenario to a full transition. An add-on investment method is used. The social-economic and social-economic project economic results are presented in net present value and do not assume any profit from overplanting. The estimated needed subsidy scheme is presented in both net present value and fixed prices and assumes 800 MW overplanting. Potential EU funding is not included in the presented results

Source: Danish Energy Agency (2023)

Notably, the results of the analyses are subject to uncertainty, including unpredictability in estimated capital costs (CAPEX) and the estimated price of electricity, since the final investment decision (FID) lies several years into the future. Additionally, significant shifts are expected on both the demand- and supply side in the energy market due to the increasing electrification in the transport sector and the expected ramp up of PtX in the energy mix. In addition, the establishment of the energy island in itself represents an unprecedented expansion of offshore wind. The scale and effect of these shifts are nearly impossible to predict.

In order to accommodate the most significant identified uncertainties, several sensitivity analyses have been conducted. Specifically, the sensitivity analyses display varying scenarios for CAPEX, the required rate of return, and forecasts of the price of electricity. The analyses are made to investigate how robust the calculated estimates are to changes in the technical assumptions, on which the calculations are based.

Finally, the report presents a number of potential project-economic benefits, such as revenue from overplanting as well as a number of potential socio-economic benefits, which are not included in the estimates. This includes increased security of supply in Denmark and Europe, greenhouse gas reduction, and Denmark becoming a net exporter of green energy.

Energistyrelsen

Background & scope

Why conduct Cost-Benefit Analyses?

As a condition for the realisation of the Energy Island in the Baltic Sea, KEI20 states that it must be profitable.

The profitability requirement encompasses the whole project from the offshore wind farm itself to the transmission network connection and the establishment of interconnectors. To evaluate whether investing in the Energy Island in the Baltic Sea is profitable, the Danish Energy Agency (DEA) has carried out cost-benefit analyses (CBAs) for a number of relevant investment scenarios. The results presented focuses on the central estimate presented in the political discussions. However, it is important to note that the results are very sensitive to assumptions and are highly unlikely to fall out precisely as assumed in this analysis. Therefore the results are also presented in various ranges to reflect the massive uncertainty. The CBAs compare the overall discounted benefits and costs from various investment scenarios to a baseline. This report outlines the applied methodology and CBA findings.

Scope

Three delimitations to the cost-benefit analysis are important to highlight.

1) The socio-economic impact beyond Denmark: The socio-economic impact is limited to effects on Denmark in accordance with the Guidance on Socio-economic Impact Assessments published by the Danish Ministry of Finance (2017)[2]. Nevertheless, the Energy Island in the Baltic Sea is a cross-border project and thus the cross-border effects in Europe are mentioned briefly.

2) Political agreements: The CBAs are calculated to inform political decision-making. Past and future political agreements are only mentioned briefly to clarify the broader context of the estimates.

3) The period beyond 2062: The analysis has a fixed study period from 2022 to 2062. The Energy Island in the Baltic Sea is expected to operate from 2030. The service life of a wind turbine is assumed to be between 30 and 35 years, and the expected service life of the transmission infrastructure is between 40 and 50 years. To line up with the average service life of the offshore wind farms, 32 years has been chosen as the timeline for the analyses, making the end period of the analyses the year 2062. The estimated cash flow is treated as an annuity. This approach is used to compensate for any costs, revenues, and scrap value after 2062.

[2] The Danish Ministry of Finance (2017): "*Vejledning i samfundsøkonomiske konsekvensvurderinger*" august 2017.

Estimate of likely profitability: Finally, it should be noted that it is only possible to estimate the likely profitability of establishing the Energy Island in the Baltic Sea, and that all profitability estimates are subject to great uncertainty. The majority of estimates rely on a number of factors and assumptions that reach several decades into the future. Examples include estimates of project costs and the development of power consumption and production in Denmark and abroad.

Furthermore, profitability assessments might be affected by future Danish and European political, regulatory, or market development, for example the future price-setting mechanisms in the hydrogen and electricity market. Therefore, no estimate should be interpreted as final. This implies that regardless of the profitability assessments presented in this report, the establishment of the energy island carries the risk of investments leading to a socio-economic and/or project-economic loss. Similarly, the establishment of the Energy Island in the Baltic Sea might lead to a socio-economic and/or project-economic gain regardless of the estimates presented in this report.

Methodology

To calculate whether the Energy Island in the Baltic Sea is a profitable investment, the DEA has carried out a CBA. The following section covers the methodology applied. The section covers (1) the scenarios that constitute the backbone of the analysis (2) the investment improvements (benefits), (3) the associated costs, (4) the required rate of return, (5) the embedded uncertainties, and lastly (6) a section on the potential revisit of the CBA during the lifetime of the investments. The section begin with an introduction to the applied CBA approach.

The scenarios were built upon the newest and most relevant information at the time, which was ENTSOE TYNDP2020. However, the targets for Europe’s RE-expansion has grown considerably in the last few years and the ENTSOE scenarios therefore quickly becomes outdated.

Scenarios

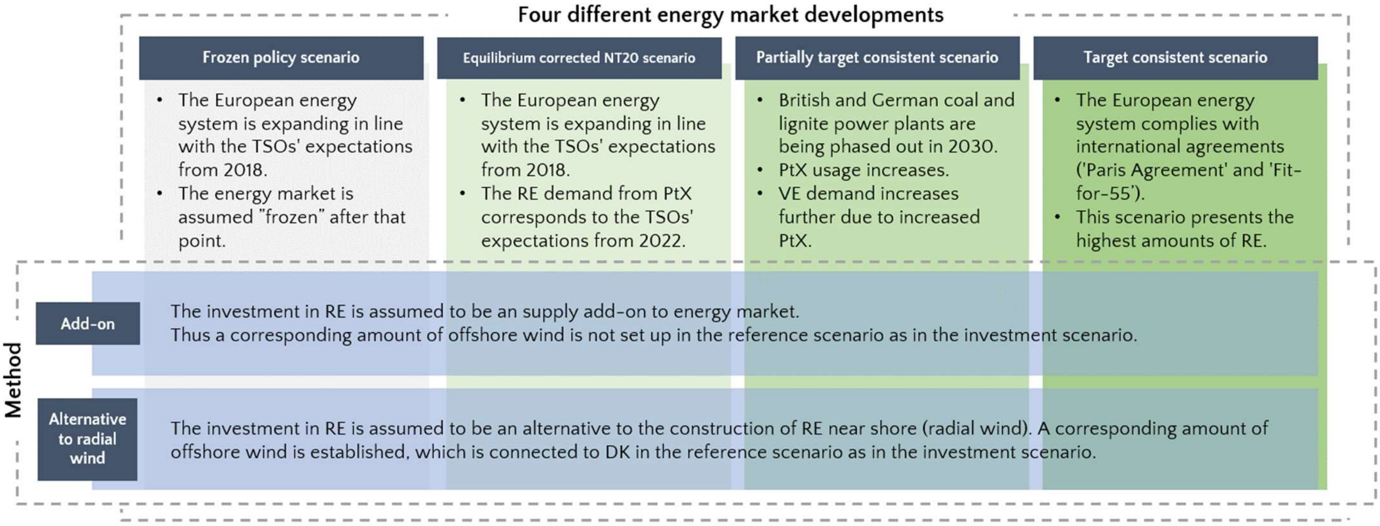
The CBA estimates the viability of investment by comparing different project scenarios to different baseline scenarios. The following subsections outline the baseline scenario as well as each of the different investment scenarios for the Energy Island in the Baltic Sea.

Approach to determine the baseline scenario

A baseline scenario is understood as an estimation of the energy market before any changes are made according to one of the investment scenarios. A solid and cogent baseline scenario is therefore vital, as it constitutes the baseline for the estimation of costs and benefits from the investment in question. The baseline scenario is stronger, the closer it is to the consensus view of the energy market. Thus, the baseline scenario must both be realistic and its assumptions intuitive in order to function as intended. Given the current fluctuations in the energy market, multiple reference scenarios are considered.

The baseline scenarios differ in assumptions regarding two variables: (1) the total renewable energy (RE) capacity and hence – electricity production, and expected electricity (and hydrogen) consumption in Denmark and abroad, named ‘energy market’, and (2) the method of how the RE capacity of the energy island is added to the baseline scenario, named ‘method’.

Figure 1 – different scenarios and methods



Source: Danish Energy Agency (2023

The ‘energy market’ variable

The variable ‘energy market’ refers to the total renewable capacity, and especially the expected electricity consumption in Denmark and abroad. Four approaches to the expected development of the European electricity market have been identified; (a) an electricity market based on frozen policy from National Trends 2020 (based on already agreed RE expansions), (b) an electricity market based on a lower estimate for the green transition developed via an equilibrium calibrated National Trends 2020, (c) a scenario which is partially target consistent with respect to the European political targets on RE expansion, and finally (d) a scenario which is target consistent with the European goals and the Paris Agreement with respect to both RE, emissions, and climate neutrality.

The four different approaches are illustrated in figure 1 and explained in more detail below.

The frozen-policy market approach (a): The first approach assumes that the baseline for the future electricity market is based on a frozen-policy principle. All profitability calculations are based on a projection based on ENTSO-E, TYNDP20 National Trends 2020. The DEA uses ENTSO-E's TYNDP20 National Trends as an approximate frozen policy scenario, as there is no frozen policy scenario for Europe.

TYNDP20 National Trends is a bottom-up scenario based on the transmission system operators' (hereafter TSOs) future expectations for supply and demand in Europe from 2018. The scenario reflects a rather limited expansion both in terms of RE and electrolysis capacity. This is explained by the fact that in 2018, when the data for the scenario was gathered, Europe had not started their green transition. The National Trends scenario therefore do not contain the plans for the massive amounts of renewable energy and electrolysis there has been planned in Europe. The capacities of both renewable energy and electrolysis in National Trends is therefore far below expectations today. This is a significant shortcoming in National Trends, which does not harmonise with the current political announcements from the EU and a large number of member states. The figures only take into account minor subsequent increases since 2018 in political ambitions regarding the green transition and the expectation of future demand for green fuels produced from PtX plants. This contributes to the fact that the supply side is not matched by expectations of increased demand, which creates an inappropriate imbalance. Expectations for production and consumption in Denmark follow the Energy Agency's report "Climate Status and Projection 2022" (KF22) where the future expectations for supply and demand is projected up to the year 2040. The figures have therefore been extrapolated from 2040 to cover the remainder of the analysis period by maintaining capacities and consumption at the 2040 level.

Lower estimate for green transition approach (b): The second approach is intended as an alternative to the frozen policy scenario since the frozen policy scenario is characterised by imbalance due to a significant rise in the supply of RE without implying a corresponding rise in demand. *The lower estimate for green transition approach* tries to correct this market imbalance by including a future increase in PtX capacity that corresponds to TSO expectations as outlined in the TYNDP22 National Trends data. Expectations regarding future supply and demand cover the period until and including the year 2040. Consequently, the results are extrapolated from the year 2040 by fixing capacities and consumption at 2040 levels. The expectations regarding production and consumption in Denmark are based on an early draft of the DEA report “Analyseforudsætninger til Energinet 2022”

(Analysis prerequisites for Energinet 2022)[3]. The main difference between the analyzed scenario and the final version of “Analyseforudsætninger til Energinet 2022” is the amount of offshore wind and PtX production, where the final version of the “Analyseforudsætninger til Energinet 2022” had an increased total of both.

The partially target consistent market approach (c): The third approach is developed by DEA as an alternative to approaches (a) and (b), both of which do not account for political ambitions and formulated goals after the year 2018. The DEA has thus developed a ‘partially target consistent’ market scenario for the development of the European energy system which adjusts ENTSO-E’s TYNDP20 National Trends forecast in the following ways:

1. Electricity production capacity from coal- and brown coal power plants in Germany and Great Britain is phased out in 2030 in line with national political ambitions.
2. European PtX production capacity is upwardly adjusted based on an expected future rise in demand for CO_2-neutral fuels. The adjustment is based on the drafted ‘Distributed Energy’-scenario in TYNDP22.
3. European RE production capacity is upwardly adjusted to accommodate the rise in demand for green electricity related to PtX production (based on a realistic amount of full load hours at the PtX facilities estimated at 3000-5000 hours). The relation between the RE-capacities of solar energy and on- and offshore wind energy in individual countries is kept constant, cf. the division used in an early draft of TYNDP22. Furthermore, RE-capacity increases yearly until the year 2050.

This third approach is only *partially* target consistent, since it includes a more optimistic forecast of future green energy transition than the TYNDP20 National Trends-scenario, but does not assume a full realisation of the goals stated in the Paris Agreement and the ‘Fit for 55’ package. For Denmark, there are the same assumptions as for scenario (b).

The target consistent market approach (d): The fourth approach is developed by EA Energy Analysis using a top-down modelling approach reflecting RE expansion, emissions, and climate neutrality consistent with the targets set in the Paris Agreement and the ‘Fit for 55’ package. In the target consistent scenario, future demand and production capacity is estimated using an investment model, and its simulations are based on the initiative portfolio from the ‘Fit for 55’ package suggested by the EU Commission in July 2021. Compared to the partially target consistent market approach (c), the target consistent scenario (d) includes a significant expansion of RE and electrolysis in Europe, including a significant expansion of offshore wind and solar capacity in the coming 30 years. The target consistent market approach also assumes a wider expansion of the transmission capacity between the Euro-

[3] https://ens.dk/service/fremskrivninger-analyser-modeller/analyseforudsaetninger-til-energinet

pean countries, allowing a larger energy distribution and more equal price of electricity across Europe. Furthermore, the approach assumes a slightly higher electricity consumption abroad. Its expectations for production and consumption in Denmark follows the same as scenario (b) and (c)

Due to historical challenges when establishing onshore wind- and solar energy, the scenario assumes a minimum level of expansion in several cases. As an example, the simulations take into account the German government's declared visions to establish 30 GW offshore wind, 100-130 GW onshore wind, and 200 GW solar energy, by 2050, by including 80 GW onshore wind and 150 GW solar energy in the calculations – instead of assuming full expansion.

The 'method' variable

The variable 'method' denotes how the energy island is added to the existing capacity where two different investment methods have been used.

- **Add-on:** In the classic method, the energy island is considered an 'add-on' to the existing energy system. The investment is added as a supply 'shock' to the market, and its profitability is compared to a situation, where neither an energy island nor a corresponding amount of RE is established. This method follows the Ministry of Finance's methodology for CBA.

- **Alternative to radial wind:** In the supplementary method, the energy island is seen as an alternative to adding new, conventional offshore wind farms to the energy system. This method highlights the profitability of choosing the energy island as an infrastructural method to connect and distribute the offshore wind energy domestically and abroad through the energy island infrastructure. The method thus highlights whether the energy island constitutes a more profitable solution than building conventional wind farms of equal capacity at the same sites. In this approach, the supply is unchanged, meaning that no supply 'shock' is added, since the effect of cancelling some wind farms and deciding to invest in others cancels out. This method isolates the effect of the infrastructure of the energy island.

The relevance of the supplementary analysis is supported by statements made at a public hearing in fall 2021 by a number of stakeholders echoing that it could be problematic to compare a scenario in which the energy island is constructed to a scenario in which no additional offshore wind in Denmark is constructed– as is the case with the add-on method. At the public hearings, the question was raised of whether a reference scenario with no additional offshore wind truly is a realistic alternative if Denmark and Europe are to reach their climate goals. The argument was made, that if the energy island would not be established, it would be necessary to build alternative renewable energy facilities with equivalent capacity. It was furthermore argued, that the energy island is a substantially large-scale project with a substantially large-scale market impact. This suggests a risk of arriving at misleading results if the calculations are conducted without assuming that an increase in energy production caused by the energy island affects consumption or other RE-projects.

These arguments demonstrate the limitations of the add-on investment method when conducting profitability calculations. In parallel, the frozen policy approach to the electricity market received critique at the public hearings. One reason why DEA developed the partially target consistent scenario (c) in the fall of 2022 was to address some of these concerns, since this scenario includes the effect on the energy market of building offshore windfarms in accordance with the Danish renewable energy targets.

As indicated in figure 1, the difference in approaches and assumptions results in seven distinct combinations – i.e. seven distinct baseline scenarios. Seven, not eight, in total, as the baseline scenario "Frozen policy with the investment as an alternative to radial wind method" is not feasible: There are no alternative conventional offshore wind farms, which the energy island can replace in a market which is assumed at frozen policy.

The next section explains the scenarios (combinations of energy market approach and investment method) to illustrate how the variables work together.

Descriptions of baseline scenarios

Baseline scenario example 1: Frozen policy scenario combined with the add-on method

In the frozen policy combined with the add-on method, it is assumed that the construction of the energy island functions as an addition to the existing electricity market at a specific point in time. That is, the energy island will be constructed, and its capacity will be added to the already existing electricity market.

In this baseline scenario, the electricity market is assumed to be composed of all the electricity production and consumption which is already in construction or politically agreed upon – also denoted as the frozen-policy assumption. This information emanates from ENTSOE's TYNDP20 National Trends, which is a proxy for a frozen-policy scenario in Europe. The TYNDP20 National Trends is typically used by DEA to conduct various analyses as it is a bottom-up scenario that is composed of the various TSOs' expectations (in 2018 for TYNDP20) to the development of the energy system towards 2040. To cover the CBA study period, the results from 2040 have been extrapolated to include 2050 as well[4].

Baseline scenario example 2: Partially target consistent scenario combined with the add-on method

This scenario is combined with the add-on method, as was the case in baseline scenario 1, and the energy island capacity is added to the existing electricity market at the time of inauguration. Thus, all other things being equal, demand is unchanged and supply is increased, resulting in downward pressure on prices. However, the result may not necessarily be reduced prices, as market mechanisms such as curtailment and PtX electricity consumption make the classic market dynamics more complex.

In contrast to baseline scenario 1, baseline scenario 2 adopts the "best-guess" assumption meaning that this scenario is adjusted to reflect the additional consumption- and production capacity, which is expected to be built given political objectives in Denmark and abroad. This is deemed relevant as TYNDP20 is based on data from 2018 and thus might not reflect the actual expectations of the market development.

Baseline scenario example 3: Partially target consistent scenario with the 'investment as an alternative to radial wind' method

In this scenario, the construction of the energy island is seen as an alternative to conventional offshore wind farms. The number of radially connected offshore wind farms and the total capacity of these farms equals the expected capacity of the energy island.
By comparing the energy island investments in the Baltic Sea with an alternative

containing radial offshore wind, the results from the CBA focus on infrastructural gains and costs. For instance, the costs of reinforcing the electricity grid along the coast where the radial offshore wind farms are placed is avoided. Similarly, the actual costs for constructing the radial offshore wind farms are avoided. Furthermore, this scenario captures the benefits of connecting different electricity markets through the energy island. In other words, by comparing the respective investment scenarios with this baseline, the CBA reflects the gains and costs from building the energy island and "moving" offshore wind farms to the location of the island and connecting to multiple electricity markets instead of building them at other relevant sites and connecting them radially.

This baseline scenario is nested in the partially target consistent scenario that includes a higher RE and PtX capacity compared to baseline scenario 1. It follows the same assumptions as in baseline scenario 2 and is adjusted to reflect the additional consumption- and production capacity, which is expected to be built given political objectives in Denmark and abroad.

Investment Scenarios: Offshore wind energy by means of the energy island

The following section covers the identified investment scenarios for the Energy Island in the Baltic Sea. The investment scenarios are chosen to best accommodate past political agreements on the purpose of the energy island with what is deemed realistic (i.e. technically and financially feasible).

The following subsection covers four different investment scenarios in the Baltic Sea:

- i) **Baltic Sea 1:** a 2 GW offshore wind construction with cable connections to Denmark (DK) and Germany (DE) in 2030
- ii) **Baltic Sea 2:** a 3 GW offshore wind construction with cable connections to DK and DE in 2030
- iii) **Baltic Sea 3:** a 3 GW offshore wind stepwise construction with cable connections to DK and DE in 2030 and 2031
- iv) **Baltic Sea 4:** a 1.2 GW offshore wind construction with cable connection to DK only

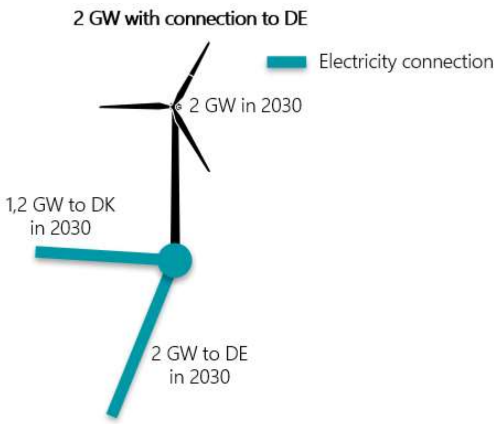
Baltic Sea 1: 2 GW[5] offshore wind with 1.2 GW cable to DK and 2 GW to DE established in 2030

The first investment scenario contains the establishment of an energy island in the Baltic Sea with a capacity of 2 GW offshore wind. In terms of cables, the scenario

4 https://consultations.entsoe.eu/system-development/tyndp2020/

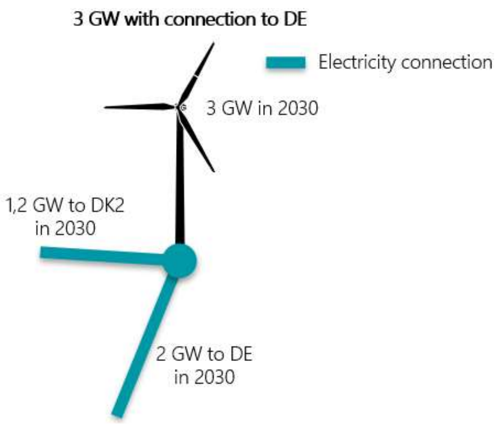
5 2 and 3 GW are referring to the minimum capacity and do not include the ability for overplanting which are decided in the tender condition in the autumn 2022.

contains a 1.2 GW cable for Denmark and 2 GW for Germany. The scenario enables establishment in 2030 but with a high risk of delays and requirements for optimising processes. The scenario is included in the CBA, as the KEI20 prescribes that the energy island in the Baltic Sea is to be realised by 2030 and have a total capacity of 2 GW.



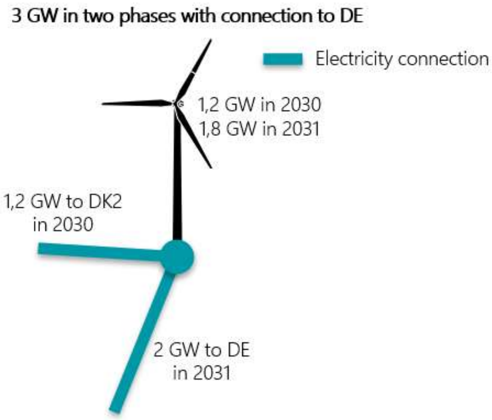
Baltic Sea 2: 3 GW offshore wind with 1.2 GW cable to DK and 2 GW to DE established in 2030

The second investment scenario contains the establishment of an energy island in the Baltic Sea with a capacity of 3 GW of offshore wind. Regarding cables, the scenario contains a 1.2 GW cable for Denmark and 2 GW for Germany. The scenario enables establishment in 2030 but with a high risk of delays and requirements for optimising processes. The scenario is analysed since it is expected that filling up the cable capacity of a total 3.2 GW, as much as possible, is expected to increase profitability. The size of the cables to Denmark and Germany respectively are chosen according to standard cable sizes in dialogue with Energinet, the Danish TSO.



Baltic Sea 3: 3 GW with 1.2 GW cable to DK and 2 GW to DE established in 2030+2031 (stepwise)

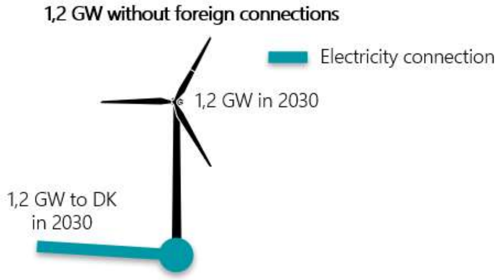
The third investment scenario contains the establishment of an energy island in the Baltic Sea with a capacity of 3 GW offshore wind – 1.2 GW established in 2030 and the remaining 1.8 GW established in 2031. As to cables, the scenario contains a 1.2 GW cable connecting Denmark to the energy island and a 2 GW cable connecting Germany. The cables are established in in 2030 and 2031, respectively. The third scenario is included in the CBA to investigate the impact of a stepwise realisation of the energy island, as the establishment of the energy island is a political project demanding bilateral coordination between Denmark and Germany. The stepwise scenario is thus relevant in case it is not possible for Germany to carry out certain political processes in time resulting in an asynchronous realisation of the cables to Denmark and Germany respectively which, in turn, results in later connection to the energy island from the German side.



Baltic Sea 4: 1.2 GW offshore wind with 1.2 GW cable to DK established in 2030

The fourth and final investment scenario contains the establishment of an energy island in the Baltic Sea with 1.2 GW offshore wind and a 1.2 GW cable for Denmark. While the scenario does not include cables connected to neighbouring markets at first, the energy island will be prepared for such later instalments. Similarly, as in the third scenario above, the fourth scenario has been included to understand the impact, if it is not possible to reach an agreement with a partner country (Germany). It represents the consequence of not connecting the energy island to Germany and helps provide a holistic overview of the establishment of the energy island.

Energistyrelsen



Overview of Investments scenarios in the Baltic Sea

Table 1 below shows a brief overview of the four different investment scenarios regarding the Baltic Sea presented above.

Table 1

Investment scenarios in the Baltic Sea

Scenario	Description	Offshore wind	Electricity connections
Baltic Sea 1	2 GW with connection to DE	2 GW	1,2 GW to DK2 2 GW to DE
Baltic Sea 2	3 GW with connection to DE	3 GW	1,2 GW to DK2 2 GW to DE
Baltic Sea 3	3 GW in two phases with connection to DE	3 GW	1,2 GW to DK2 2 GW to DE
Baltic Sea 4	1,2 GW with no connections to other countries	1,2 GW	1,2 GW to DK2

The calculated net-results of the four investment scenarios mentioned above were presented to the politicians in the summer of 2022. Table 2 and 3 below displays the results. Based on these, it was decided to expand the capacity of the Energy Island in the Baltic Sea to 3 GW with realization in 2030 in the political agreement “Tillægsaftale om Energiø Bornholm 2022” from August 29th, 2022. Hence, the following CBA focuses only on the corresponding scenario “Baltic Sea 2”.

Table 2

Socio-economic and project-economic impact of different investment-scenarios. June 2022.

DKKbn (2022 prices, net present value)	Socio-economics	Socio-economic project-economics
Baltic Sea 1: 2 GW with connection to DE	-7 to 7 w. a. central estimate of -1	-13 to 1 w. a. central estimate of -7
Baltic Sea 2: 3 GW with connection to DE	-11 to 9 w. a central estimate of -2	-18 to 2 w. a central estimate of -10
Baltic Sea 3: 3 GW in two phases with connection to DE	-12 to 8 w. a central estimate of -4	-18 to 2 w. a central estimate of -10
Baltic Sea 4: 1,2 GW with no connections to other countries	-20 to -13 w. a central estimate of -17	-19 to -10 w. a central estimate of -15

Note: The politicians involved in the overall settlement was presented to the results regarding the 3 GW investment scenario and the 2 GW investment scenario from the above table.

Source: DEA (2023)

Table 3

DEA's supplementary profitability calculations, which treat the Energy Island in the Baltic Sea as an alternative to the construction of radial wind near Bornholm. June 2022.

DKKbn (2022 prices, net present value)	Socio-economics	Socio-economic project-economics
Baltic Sea 1: 2 GW with connection to DE	3 to 12 w. a. central estimate of 7	-12 to 3 w. a. central estimate of -6
Baltic Sea 2: 3 GW with connection to DE	1 to 15 w. a. central estimate of 7	-14 to 8 w. a. central estimate of -5
Baltic Sea 3: 3 GW in two phases with connection to DE	0 to 13 w. a central estimate of 6	-14 to 7 w. a central estimate of -5
Baltic Sea 4: 1,2 GW with no connections to other countries	-9	-16 to -7 w. a central estimate of -13

Note: The politicians involved in the overall settlement was presented to the results regarding the 3GW investment scenarios in the above table.

Source: DEA (2023)

Benefits

This section provides an overview of the benefits considered in connection with the CBA. The section covers i) the applied categorisation of benefits; ii) the actual identification of benefits and iii) an outline of the applied estimation methods.

Categorisation of benefits

The benefits are categorised into (i) project-economic benefits and (ii) socio-economic benefits. Project-economic benefits include positive impacts on project investors such as revenues, improved strategic positioning or, reputation. The project-economic benefits also play into the total socio-economic CBA. Socio-economic benefits include positive impact on a societal level counting electricity consumers, and already existing electricity producers. By including these benefits we strive to display the profitability from a societal perspective.

Identified benefits

The CBA covers the benefits seen in table 4. Most of the identified benefits are quantified and included in the results, while others comprise potential upsides and effects to the results but have been deemed impossible or near impossible to measure in particularly without bias.

Table 4

Overview of benefits and upsides

Benefit & Category	Identified	Potential upside (unquantified)
Project-economic benefits		
Revenue from electricity sales	✓	
Congestion rents from new cables	✓	
Revenue from overplanting		✓
Revenue from hydrogen plants		✓
Revenue from renewable energy shares (RES)		✓
An innovation hub for green energy	✓	
Socio-economic benefits		
Consumer surplus	✓	
Producer surplus	✓	
Saved costs from radial farms*	✓	
Congestion rent from existing bidding zones	✓	
Improved security of supply		✓
Greenhouse gas reduction**		✓
Saved costs from network reinforcements*		✓
Economies of scale with the realisation of new islands		✓

*Saved costs from radial farms are only included as a benefit in scenarios, where the energy island is established as an alternative to radial wind. The lost revenues are included as a cost in the next chapter of the report.
**No additional reduction in GHG emissions follows from project scenarios considered as an alternative to radial wind. This is a direct consequence of the fact that the pertaining reference scenarios assume that an equivalent amount of offshore wind capacity is being established elsewhere.

Identified project-economic benefits

This section covers the identified project-economic benefits, which are included in the CBA.

The project-economic benefits consist of earnings from the electricity sales from the offshore wind farms and congestion rents from new cables (the profit derives when selling electricity from a low- to a high-price bidding zone due to capacity limitations in the electricity grid), which is established via the energy island.

Revenue from electricity-sales: One of the major benefits, seen from a project-economic perspective, is the revenue generated from electricity sales to consumers in Denmark and abroad.

Congestion rents from new cables: Congestion rents occur as a result of the new cable connections and bidding zone due to limitations on the transmission capacities between bidding zones. The revenue is earned by the TSO that owns the cable. In line with EU-law, the revenue has to be used to ensure the availability of cross-border capacity or for cross-border electricity infrastructure development.

This makes it a benefit for consumers, as they would otherwise help finance such measures via grid tariffs. Congestion rents are described in detail below in the socio-economic benefits section.

Transfer of Energinet's costs: Danish political agreements outline that Energinet should transfer as much of its costs to the future owners of the offshore wind farm. EU law outlines that network operators apply cost-reflective costs to the grid users which is expected to cause co-financing of Energinet's costs between the owners of the wind farms and the consumers. The financing is specified in the tariff methodology on the energy island, which is developed by Energinet and subject to the approval by the Danish Utility Regular (Forsyningstilsynet). It is, however, also assumed that possible EU funding will offset part of the collected transfer of costs. While the transfer of Energinet's costs will have a positive impact on the project-economic estimates, the extent to which the transfer impacts the socio-economic estimates depends on whether or not costs are transferred to Danish consumers (e.g. through higher tariffs). If costs are transferred to Danish consumers, the transfer will impact the socio-economic results – however, since the project economics is part of the socio-economy the total will remain the same, regardless of who the cost is transferred to.

Based on the regulatory framework, and according to the draft tariff methodology developed by Energinet, the transfer of Energinet's costs related to interconnectors is assumed to be split 61/39 between the concession winner (the future owner(s) of the wind farms) and the consumers, while costs related to the transmission on the energy island are assumed to be transferred 100% from Energinet to the concession winner.

Revenue from overplanting: It should be noted, that revenue from overplanting is only included in the estimated need for a subsidy scheme. It is not included in the CBA base results.

Overplanting as a term refers to the right of the wind farm owner(s) to optimise the transmission utilisation by increasing the wind power capacity above the transmission capacity limit[6]. This is expected to result in added revenue since full wind power capacity is not expected at all times. However, there are rational limits to overplanting. The owner of the wind turbines must pay for the construction of the wind turbines and the seabed reserved for the wind turbines has a limited size and must only be overplanted up to a 'shadow' limit[7] set by DEA.

[6] In general, the capacity may be expanded in part by installing additional wind turbines or in part by increasing the generator size of the turbines. This depends on the terms of the contract between the landowner and the future wind turbine owner. Often, some flexibility within a capacity span is granted to the future wind turbine owner.

[7] The shadow effect is the level of which a single wind turbine hinders another from rotating because it is blocking the wind.

When an overplanting strategy is pursued, the wind turbines will have to be curtailed (actively prevented from producing) at times. However, if the additional wind capacity is connected to and used for PtX there are no immediate overplanting constraints resulting from capacity limits in the electricity grid. Since there will be no contractual bindings guaranteeing any amount of overplanting to be realised by the future owners of the wind farm(s), the estimated effect of overplanting on project- and socio-economics is subject to great uncertainty.

The updated estimates of the need for a subsidy scheme assume 800 MW overplanting, which is the maximum capacity according to the completed assessment of the effects of the Energy Island on the environment (SMV)[8].

Potential upsides – unquantified project-economic benefits

This section covers the potential upsides for the project-economics, which are unquantifiable and hence not included in the CBA.

EU funding:

The EU Commission has a variety of funding instruments to promote the green transition, growth, competitiveness, innovative low-carbon technologies, and interconnected trans-European networks within the energy sector. The Connecting Europe Facility Energy (CEF Energy) and the Innovation Fund are two relevant examples of such funding instruments. The first instrument focuses its funding on cross-border renewable energy projects, interoperability of networks, and better integration of the internal energy market, while the ladder focuses on innovative low-carbon technologies. The energy island project is a particularly good match with the above-mentioned criteria due to the innovative nature of and energy island concept and because of the connection to Germany and potentially other European countries.

Due to the unprecedented nature of the energy island, relevant comparisons have been hard to determine. However, by looking at other large-scale construction projects within the Danish energy sector, a lower bound has been estimated.

It is the interconnector, which may receive EU funding. Thus, what needs to be estimated is the fraction of TSO costs expected to be covered. In 2013, the Danish TSO, Energinet, presented a business case regarding the construction of an interconnector (the COBRA cable) between Denmark and the Netherlands in collaboration with the Dutch TSO, TenneT. Construction started in 2016, and the cable was finished in 2019 with the purpose to improve the European transmission grid and thus increase the amount of variable wind power in the system while improving

[8] DEA (2023): *Miljøvurdering af planen for Energiø Bornholm*. Link: https://ens.dk/ansvarsomraader/energioeer/miljoevurderinger-energioe-bornholm/miljoevurdering-af-planen-energioe

supply reliability. The CAPEX of the project amounted to 4,758 million DKK (2013 prices). The project received 645 million DKK (2013 prices) in financial aid from the EU Commission's "European Energy Programme for Recovery" which corresponds to approximately 14% of the CAPEX. Using this share of EU funding related to the CAPEX for the Energy Island in the Baltic Sea, corresponds to approximately 1.1 billion DKK.

The Danish Ministry of Finance has addressed the topic of EU funding within the framework of a CBA in the publication "Guidance in socio-economic impact assessments"[9]. According to the guidelines, EU grants is only included as long as they are project specific and independent of other EU grants given to Denmark, as to make sure, that there is no opportunity cost of the particular EU grant. Grants received from CEF Energy and the Innovation Fund are indeed project specific but could constitute an opportunity cost, because EU grants are geographically conditioned.

However, due to timing, regulations, and negotiations with the EU Commission, the process of applying for funding will not be set in motion until primo 2024. In parallel, DEA is exploring whether other EU funds might be available or relevant to apply for, given that the EU is seeking to accelerate the green energy transition and therefore regularly adds new investment incentives. Thus, it is too uncertain at the time of writing, to say whether or not and to what extent the Energy Island in the Baltic Sea will receive EU funding.

Revenue from hydrogen plants: The revenue from converting electricity to hydrogen and other PtX solutions has not been quantified since too little is known on the development of this market and sector from 2030 onwards. It is, however, known that production volumes will vary according to the PtX plants' willingness to pay – i.e. they are willing to purchase power up to a certain price level in order to generate an income from operating[10]. Only then will the plants purchase and consume power. As the PtX plants' willingness to pay has a significant effect on power price estimates, sensitivity analyses with different levels of willingness to pay, resulting in different power prices, are carried out later in the report. Also, the cost-benefit results are presented as a high, central, and low estimate according to whether the results are based on a high, central, or low price for hydrogen.

No investment scenario assumes direct revenue from PtX, as the revenue from hydrogen plants (or other forms of PtX) is considered too difficult to estimate to enter as direct input in the cost-benefit analysis. Furthermore, no large-scale PtX plant

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[9] Danish Ministry of Finance/Finansministeriet (2017): "*Vejledning i samfundsøkonomiske konsekvensvurderinger"* august 2017.

[10] If the revenue from hydrogen plants were to be calculated, it would be assumed equal to the difference between the market price of hydrogen subtracted by the cost of buying the implied volume of electricity.

has yet been realised, and it is therefore also uncertain whether direct revenues from PtX-production will be technically feasible.

Revenue from Renewable Energy Shares (RES): Denmark has already met the binding EU climate and energy targets set for 2020 to 2030. Other countries may reach their binding targets by buying the exceeding RES from countries like Denmark. Denmark is currently able to generate income from the statistical transfers. However, the precondition is the existence of a market for RES after 2030, which is yet to be determined. After 2030, the price of RES can potentially amount to a price above zero, if the European Union sets new targets after 2030, and if the statistical transfer of renewable energy shares from other countries continues to be a method for achieving binding targets in a rapidly changing market. Due to the substantial uncertainty, a potential income from such sales has not been included in the CBA. However, RES may play a part in the TSO agreements regarding joint payment for the construction of interconnectors. The transfer of RES is part of the agreement with 50Hertz regarding the interconnector cable to Germany from the Energy Island in the Baltic Sea.

Congestion rents and producer and consumer surplus additional to estimated levels: The cost-benefit estimations indicate that congestion rents have a significant impact on the project-economy and socio-economy of the energy island. The following upside has not been included in the profitability calculations.

The revenues generated by trading electricity between bidding zones occur, if the capacity of the transmission connection is utilised to its maximum, and a price difference between two bidding zones remains. In situations with e.g. breakdown, abnormally low wind activity or unscheduled maintenance, severe price spikes can happen. This “outlier situation” drives up the congestion rents. However, RAMSES does not model these events, as they rarely occur, and it is not possible to predict when it happens. Thus, congestion rents carry a risk of being projected below their realised values.

Since the energy markets in Denmark and Europe are currently undergoing fundamental changes and are gradually developing into increasingly connected markets, through more and more interconnectors, congestion rents during “normal” hours might change. Furthermore, congestion rents are traditionally split equally between involved TSOs but this cannot necessarily be assumed going forward as the energy market will change, especially if the plans for large scale wind farms in the North Sea materialize with large grids of infrastructure in between. In this market it will not be as clear as currently who should get split the congestion rent. Finally, producer and consumer surplus is also likely to be affected by “outlier situations” in the future.

To conclude, predictions of congestion rents are embedded with high uncertainty, and there is a likelihood that estimates are below the realised values.

The effect of weather and wind

Weather and wind can be of great importance for assessments of the socio-economic trade effects (producer surplus, consumer surplus, and congestion rents), as variations in e.g. wind conditions become more and more important for the electricity system and dynamics therein.

Energinet's business case for the Energy Island in the North Sea electricity infrastructure in project scenarios with 3-4 GW offshore wind and a connection to Belgium is based on analyses of 35 historical years of weather conditions (1982-2016) based on ENTSO's ERAA21 and TYNDP20.

Energinet's business case also shows the effect of considering only one normal year for Danish weather conditions (2008). Energinet's analyses show that the socio-economic effects vary considerably across the 35 historical weather years. Crucially, the analyses show that the average socio-economic effects across the 35 weather years are significantly greater (several billion Danish kroner) than the corresponding effects in Energinet's normal weather years. This indicates that the use of just one average/normal weather year in analyses can potentially imply a significant underestimation of the socio-economic effects.

Energinet's results cannot be transferred directly to the analyses of the Energy Island in the Baltic Sea and results presented in this material due to a number of differences in assumptions and methods, but they substantiate a potential upside of considerable size.

Info box provided by Energinet (Jan-2023)

Energinet’s analysis indicates that the value is underestimated. However, this is not explored further in the cost-benefit analysis. In addition, the historical climate years 1982 – 2016, all else being equal, must be expected to be 'more normal' with fewer outlier events than in the coming decades. This is due to weather conditions gradually becoming more volatile and extreme due to climate change. This is also due to an electricity system that will consist of more RE and fewer so-called ‘dispatchable’ energy sources, which can be switched on and off to stabilise the energy system. On the other hand, it must also be expected that an electricity system will be developed which continuously gets better at handling these. If nothing else, then in the long run. All in all, the potential underestimation of outlier effects has been deemed unquantifiable.

An innovation hub for green energy: The Energy Island in the Baltic Sea is among the first of its kind, suggesting that Denmark has the opportunity to accumulate regional knowhow and expertise, which will be highly sought after in the coming years enabling Denmark to strengthen its position as an innovation hub for green energy. This can potentially entail an inflow of foreign direct investments, the creation of jobs, and the export of both know-how and technology. However, given that such an effect is nearly impossible to estimate, it is not included in the CBA.

Identified socio-economic benefits

This section covers the identified socio-economic benefits, which are included in the CBA.

Consumer surplus: The benefit electricity consumers receive, calculated as the change in electricity prices times the quantity demanded. Electricity consumption is assumed constant. Moreover, revenue to cover the TSO net costs, which at the time of writing likely cannot be compensated for in any other way, may fall on the consumers as a surcharge.

Producer surplus: The producer surplus is defined as the earnings producers receive after supplying power to the electricity grid. This also includes earnings from other types of technologies (e.g. solar power and onshore wind). The surplus is estimated as income from electricity sales minus the production costs at the time of the electricity production[11].

Saved costs from radial wind farm solution[12]: For all project scenarios, where the energy island is constructed as an alternative to radial wind, the costs associated with establishing equivalent amounts of wind power in the reference scenarios are saved. These savings are considered a socio-economic benefit in the CBA on the grounds that if they were not, the net results of the project scenarios would reflect a situation, where both the energy island and the equivalent near-shore wind farms would be established. Notably, the expected revenue from the cancelled radial park is subtracted from the socio-economic CBA results in parallel.

Congestion rents from existing bidding zones: The different investment scenarios might influence congestion rents[13] from already existing bidding zones differently. As is the case for many of the elements in the CBA, it cannot be determined beforehand whether congestion rents from existing bidding zones will generally count as a benefit or the opposite.

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[11] For more information see DEA (2022): "Notat – Dokumentation af energiø-analyser udarbejdet i Systemanalyse med Ramses-modellen"

[12] Saved costs from radial farms are only included as a benefit in scenarios, where the energy island are established as an alternative to radial wind. The lost revenues are treated in an identical manner in the next chapter of the report.

[13] Please see the explanation of congestion rents above.

Potential upsides – unquantified socio-economic benefits

This section covers the potential upsides for the socio-economics, which are unquantifiable and hence not included in the CBA.

Improved security of supply: By establishing more interconnectors, the risk of energy shortages, e.g. brownouts our blackouts, decreases, as the Danish power grid is enabled to draw from a larger variety of energy sources.

Green House Gas (GHG) reduction: A potential upside may be derived from production of hydrogen with the resulting reduction in fossil fuels used for heavy transportation. However, whether the Energy Island in the Baltic Sea in itself contributes to GHG reduction depends on whether it is considered an alternative to radial wind or as an add-on, since no actual additional GHG reduction will follow from establishing the energy island as an alternative to an equivalent amount of radial wind power.

Saved costs from network reinforcements: Part of the rationale behind establishing the Energy Island in the Baltic Sea with an interconnector is to reduce the amount of onshore energy infrastructure. All else being equal, this causes financial savings in the form of fewer onshore grid reinforcements and a reduced need for backup capacity compared to a radial reference. If radial wind farms of equal capacity were built instead of the Energy Island, a larger onshore grid reinforcement would most likely be required. Choosing the Energy Island as an infrastructure solution thus represents a saving in this regard. This saving has not been quantified in the results of the report. Similarly, the potential need for reinforcement of the Danish power grid is not included. However, the expected costs of network cable infrastructure toward Danish shores and connection points are included in the CBA. Energinet has advised on the approach and estimation assumptions. The cost is excluded as it is deemed very difficult to estimate currently, in which order expected offshore wind turbines is built and thus not possible to determine why one wind turbine construction should pay for the reinforcement onshore, while another wind turbine construction will is not.

Denmark as a net exporter of green energy: An energy island promotes the possibility of becoming a net exporter of renewable energy and contributes to the green transition of other countries via its foreign connections. In addition, in profitable scenarios, the project can inspire other countries to be more ambitious, e.g. by showing how the costs of green transition can be minimized with an energy island concept for the development of future infrastructure for the production of renewable energy.

Applied methodology for estimating benefits

The following section explains the methodology of how benefits are calculated. All prices are estimated using a certain year as the price level base year (2022).

Power Prices
The expected power prices and consequent sale of electricity represent the largest economic benefit for the owner of the offshore wind farm, while the differences in power prices between the connected areas are the main drivers for the socio-economic benefits of establishing interconnectors via the energy island – i.e. the congestion rents. DEA's power system model RAMSES estimates the future power prices for each country in Europe. RAMSES is a bottom-up dispatch model used for many different analyses in the DEA´s work and used in key publications such as "Klimastatus og –fremskrivning" (climate status and projection).

The modelled power prices are a result of a variety of inputs and assumptions about the future power system in Europe. Assumptions are made on a number of inputs in order to transcribe future power prices. Key examples of such inputs are listed;

- The development in power (and hydrogen) generation in different bidding zones [14]
- The development in power (and hydrogen) consumption levels
- Future network reinforcements
- Future network flexibility investments and the extent to which different bidding zones are expected to be connected in the future
- Future consumption patterns concerning both electricity and hydrogen
- Future fuel and CO2 emission costs

The inputs listed above are highly interdependent meaning that power prices in the Danish bidding zones are highly dependent on connections to foreign countries. Hence, the modelled power prices in Germany, The Netherlands, Sweden, Norway, and the United Kingdom are co-defining the power prices in Denmark. The uncertainty of estimating the power prices with regard to the CBA study period is addressed in a separate section later in this report.

Producer Surplus
The producer surplus is also estimated with RAMSES and is a result of a system optimisation estimated by deducting the variable production costs which are dependent on production facility types and fuel prices etc. from the revenues generated from the sale of electricity on the spot market which can be expressed as follows:

$$PS_p = spot_{incom\ p} - MC_p$$

For the separate bidding zones, the total producer surplus is thus equivalent to the sum of producer surplus for all electricity producers:

[14] The estimated revenue from electricity sales is dependent on the estimated production of electricity from the islands in each of the investment scenarios. The latter estimate account for potential blockage effects (i.e. the phenomenon in which the energy from wind turbines is reduced due to 'shelter' from neighbouring turbines).

$$PS_z = \sum_{\forall p \in z} spot_{inco \quad p} - MC_p$$

Congestion Rents

Congestion rent is also estimated using RAMSES and is estimated for each trading connection between the bidding zones, and is a result of the final system optimization resulting from the introduction of the energy island. Congestion rents are defined as the price differences across bidding zones. This is multiplied by the flow between the bidding zones on an hourly basis. The estimation can be expressed as follows:

$$C_{z,zz} = \sum_t (P_{z,t} - P_{zz,t}) |flow_{z,zz,t}|$$

Congestion rent can only occur in periods of full connection to trade since only then can a price difference between two bidding zones arise. On a yearly basis, the separate countries' congestion rents are calculated under the assumption that such additional revenue is split evenly between the bidding zones:

$$C_{zone} = \sum_z \frac{C_{z,zone}}{2}$$

Revenue from overplanting

The value of overplanting is estimated by assuming the connection of excess offshore wind capacity along with the corresponding electrolysis capacity which is connected to the excess offshore wind via direct lines.

The value of overplanting is fundamentally driven by the difference in value between selling the extra electricity production in hours with high prices using already established electricity infrastructure from the energy island – and the cost of this extra electricity production. In estimating the value, several derived effects are taken into account such as the effect on the trade value between the countries connected to the energy island, changes in consumer and producer surplus in the Danish bidding zones, and changes in the value of both new and existing congestion rents (this is estimated using RAMSES and the energy market model).

The updated base scenarios for the Energy Island in the Baltic Sea do not assume overplanting, however, the updated estimates of the need for a subsidy scheme assume 800 MW overplanting, which is the maximum capacity according to the completed assessment of the effects of the Energy Island on the environmental (SMV).

Costs

The following section outlines the costs or disadvantages associated with the Energy Island in the Baltic Sea by looking at i) the applied categorisation of costs, ii) the actual identification of costs, and iii) an outline of the applied estimation method.

Categorisation of costs

The CBA distinguishes between (i) capital expenditures – CAPEX, and (ii) operational expenditures – OPEX, besides (iii) other costs not applicable to either of the aforementioned. CAPEX and OPEX are split into the following three cost categories: 1) Costs related to the wind turbines incl. foundation and installation costs, 2) power systems, 3) and the cable infrastructure incl. interconnectors.

Identified costs

The CBA covers costs related to the categories seen in table 5 below.

Table 5

Cost categories

Category and sub-elements

Wind turbines	Cable infrastructure incl. interconnections	Power systems
Materials	Sea cables	HVAC equipment
Foundation	Land cables	HVDC platform
Grid connection	OPEX (1%)	HVDC/HVAC Platform
OPEX (1.5%)		DC breakers
		Converters
		Buildings
		OPEX (1%)

Source: The Danish Energy Agency (2023)

CAPEX

CAPEX covers the acquisition, maintenance, and upgrading of physical assets.

The following section describes the data sources used to estimate the two main types of CAPEX-related costs including i) costs associated with the wind turbines incl. foundation and installation costs and ii) the cable infrastructure and the power systems.

Wind turbines: The estimated costs of offshore wind turbines and wind turbine foundations are based on calculations from EMD International A/S as part of the work for the DEA's technology catalogues[15].

[15] DEA (2022). *"Technology Data – Energy Plants for Electricity and District heating generation"*. June 2022. Link: https://ens.dk/sites/ens.dk/files/Analyser/technology_data_catalogue_for_el_and_dh.pdf

Cable infrastructure & power systems: All cost estimates related to the power systems and cable infrastructure are provided by the Danish TSO, Energinet.

The estimation of costs – including the estimation of uncertainty – is addressed in a later section of the report.

OPEX

OPEX covers the day-to-day operations i.e. maintenance, crew, wear and tear, as well as costs associated with yearly inspections and quality reviews, potential repairs and replacements.

Other Costs

The following costs have both CAPEX and OPEX elements and are thus treated within a separate, third category.

Unachieved revenues from radial park solution: For all project scenarios, where the energy island is constructed as an alternative to radial wind, the subtraction of the expected revenue from the cancelled radial park is a cost subtracted from the socio-economic CBA. The revenues remain as part of the project-economic CBA.

The annuity principle and scrap values: Each larger capital expenditure component is treated as a cash flow annuity in the CBA model. This means each component has an individually estimated lifetime and that the cost of each component is split linearly across its lifetime. The component costs are thus treated as annual negative cash flows during the entirety of the study period. In this way, the CBA allows for the comparison of different investment scenarios with different construction periods and technical lifetimes. Also, this method implies that the remaining value of any investment by the end of the study period (scrap value) is not included in the CBA. As such, the scrap value of each investment is accounted for by using the annuity principle. This is in accordance with the DEA's regular practice with regards to social economic analyses within this subject area[16].

The vast majority of assets have a lifetime longer than the study period. The negative cash flow which has not yet been incurred within the study period is treated as an annuity with respect to the remaining cost from 2065 (when the study period ends).

ABEX: Since the lifetime of most assets lasts longer than the study period of the CBA, abandonment expenditures have not been taken into account. In general,

[16] DEA (2021): *"Vejledning I samfundsøkonomiske analyser på energiområdet 2021"*. July 2021. Link: https://ens.dk/sites/ens.dk/files/Analyser/vejledning_i_samfundsoekonomiske_analyser_paa_energiomraadet_2021.pdf

ABEX may vary substantially[17] according to the physical context and local regulation, as well as the choice of materials and expected lifetime of the assets. Thus expanding the study period substantially to cover the time of potential abandonment in the far future would be an estimation embedded with substantial uncertainty. This has not been deemed meaningful.

Transmission availability: TSO's may at times need to limit transmission availability with the intention of solving capacity limitations internally in their own bidding zones. However the current Electricity Regulation (EU) only allows the TSO's to limit the cable capacity down to 70% between bidding zones. If the limit is superseded, the TSO is required to compensate the producers for lost revenue.

According to Energinet, the historical transmission availability between DK2 and DE is estimated at 88% from 2015-2020. Consistent with this level, an availability of 90% on all cables is assumed in this analysis since this is also the standard transmission availability level applied in analyses conducted by DEA. 90%, and not the lower boundary at 70%, is also chosen due to an underlying assumption that the local transmission network will be expanded in the coming years which would lower the need to limit transmission availability, in the first place.
By assuming an availability of 90% instead of 100%, the estimates still account for occurrences of limited capacity which are expected to happen very rarely and only in hours with large RE-production and thus low prices.
The assumption of 90% transmission availability, all else being equal, constitutes a potential downside for the profitability. The 10% unavailability covers a) technical downtime due to broken cables and maintenance. This corresponds to 5% of the downtime. And b) market-driven TSO interference due to internal bottlenecks inside the bidding zones connected to the energy island, this constitutes the remaining 5% reduction in availability.

90% transmission availability is considered a realistic downside. Due to previous challenges with the transmission availability from Denmark (DK1) to Germany, actual availability. However, it can also be lower than 90%, to the fact that Germany's internal power grid is not developed enough to transport electricity from the north to the heavily industrial areas in southern Germany. Energinet assesses, however, that these bottleneck challenges in Germany's internal network are not an issue from DK2 to Germany, at least not nearly to the same extend.
In addition, Germany is expected to invest in its transmission network in order to fulfil the signed declaration to harvest 150 GW offshore wind in the North Sea by 2050.

[17] ABEX for individual assets may be equal to CAPEX with a +/-50% uncertainty (Source: SWECO (2021). "Analyse af tekniske koncepter for Energiø". december 2021. Pp. 42)

TSOs' control over transmission flows imply a risk of 'beggar-thy-neighbour' behaviour leading to lost revenue – e.g. when neighbouring markets prioritise to use domestic green energy production and not buy green energy from Denmark.

Excluded Costs

The following costs have been considered near impossible to estimate or irrelevant to consider due to their limited size relative to other costs. Although no exact approximation, it is still relevant to consider the following costs as unspecified downsides, relevant to several investment scenarios.

Administrative costs: Ordinary costs associated with DEA's ongoing tasks and administering regular authority tasks which are not exclusive to the energy island are considered costs held regardless of the investment decision and are thus not included in the CBA.

The Net Tax Factor: The cost is typically used to convert factor prices into market prices making them more comparable to society's willingness to pay. However, it should be noted that the Net Tax Factor is based on calculations on duty charges (i.e. a form of tax) as well as government spending in Denmark. In addition, the energy island is international by nature and thus subject to several tax factors regardless. Therefore, the Net Tax Factor is not accounted for in the CBA.

GHG emissions: The construction of the Energy Island in the Baltic Sea will result in greenhouse gas emissions during the construction itself, as is the case for all infrastructure projects.

No analysis has been made to predict the level of emissions in the phase of operations and later during decommissioning. However, based on previous studies, it may be assumed that ~20% and ~1% of GHG emissions will be derived in these two phases respectively. The figures are likely to be reduced under the assumption of new technology further reducing the estimated lifecycle emissions.

Applied estimation methods for costs

This section covers the cost estimation methods. All prices are estimated using a certain year as a price level base year. Given the timeframe of the analysis, it was decided to keep the original price level base year of 2022 instead of updating it to 2023 levels. The section starts with the estimation of CAPEX as OPEX is derived as a percentage of CAPEX.

CAPEX estimation method

The underlying CAPEX estimation methods and assumptions are addressed in summary terms.

In the original profitability estimations in spring 2022, a risk premium on CAPEX according to the estimated premium preferred by each individual estimation source was added. In the updated profitability estimations, a consistent 10% risk premium on CAPEX is applied to add transparency and treat all costs equally, despite the estimation source.

Wind turbines including foundation: Cost estimations are based on the following assumptions[18];

- A maximum area uptake of 0.22 km2/MW
- A future turbine output of 15 MW
- a park size of 1 GW which is connected to the onshore transmission grid
- a gross area 30% larger than necessary to allow for overplanting

The cost estimations assume that the wind turbines are installed in the conventional way, where jack-up ships are used, which are stabilised using monopole legs submerged on the seabed.
The costs of the wind turbines incl. the foundation and the cable infrastructure include project management and risk premium. The estimation of costs follows the approach outlined in DEA's technology catalogue on offshore wind[19]. However, COWI has analysed the specific location next to Bornholm and found there are constraints in the cable corridors going into shore. COWI, therefore, estimates that it is necessary for the concession winner(s) to convert their power up before it reaches the shore in order to reduce the amount of cable capacity. This will lead to additional costs, compared to a standard radial wind farm. This additional cost is included in the total below in table 6 and is based on the estimates in COWI's CBA report from 2021[20].

Cable infrastructure and power systems: Energinet's estimated CAPEX related to cable infrastructure is split into the cost of the cable running from the island of Bornholm to Zealand and the power systems required to convert the power to the required voltage levels and frequency

Energinet's estimated CAPEX related to power systems is split into the costs of AC/DC converters and DC breakers. Costs for HVDC platforms and HVDC/HVAC platforms include cost estimates for a modular mono-polar HVDC transmission sys-

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[18] DEA (2022). *"Technology Data – Energy Plants for Electricity and District heating generation"*. June 2022. Link: https://ens.dk/sites/ens.dk/files/Analyser/technology_data_catalogue_for_el_and_dh.pdf
[19] DEA (2022). *"Technology Data – Annex to Performance and cost development"* March 2022. Link: https://ens.dk/sites/ens.dk/files/Statistik/technology_catalogue_offshore_wind_march_2022_-_annex_to_prediction_of_performance_and_cost.pdf
[20] https://ens.dk/sites/ens.dk/files/Vindenergi/a209704-001_cost_benefit_analyse_endelig_version.pdf

tem. Since the technical setup of the AC/DC converters and DC breakers is relatively untested and only a few converters and breakers of the needed type exist today, these cost estimates are subject to great uncertainty.

Table 6 summarises the estimation of the most central elements in Energinet's CAPEX estimates as of September 2022. It should be noted, that Energinet sets aside an amount corresponding to 36% of the estimated sum of CAPEX to account for project management, risk, and reserve[21].

Table 6

Costs

DKKbn (2022 prices, net present value)	**Estimated CAPEX**
Wind turbines	**46,3**
Cables to DK	**3,9**
Power systems	**7,8**

** Costs covered by DE*

Source: The Danish Energy Agency (2023)

OPEX estimation method

The following subsection covers the estimation of OPEX, which is derived as specific fractions of CAPEX for each of the three types of costs; i) costs associated with the wind turbines incl. foundation, and ii) the cable infrastructure.

Wind turbines including foundation: Sweco estimates OPEX related to the wind turbines including the foundation as 1.5% of the CAPEX base of the Energy Island in the Baltic Sea.

Cable infrastructure: Energinet estimates OPEX for the cable infrastructure at 1% of the related CAPEX base (excluding reserves) consistent with Danish TSO's application for a permit to initiate construction (the so-called "§4 application")[22].

Required rate of return

Finally, comes the required rate of return, which informs what future cash flows are worth in the present when discounted by the required rate of return (the so-called "cost of capital") of each respective investor.

[21] The risk premium methodology applied to Energinet's CAPEX estimate is "Ny Anlægsbudgettering" (NAB). This is not the risk premium methodology that Energinet usually applies, however NAB is applied with regards to the CBA estimates to be consistent with the other cost estimates DEA uses in the CBA. NAB is preferred as it is a known risk premium methodology in infrastructure projects characterised by many uncertainties.

[22] COWI (2021). *"Cost benefit analyse og klimaaftryk af energiøer i Nordsøen og Østersøen"*. Januar 2021. Link: a209704-001_cost_benefit_analyse_endelig_version.pdf (ens.dk)

Energistyrelsen

The socio-economic discount rate

The socio-economic discount rate is the Danish state's required rate of return. It is also used to discount the future socio-economic cash flows to understand their value in the present. The socio-economic discount rate is provided by the Danish Ministry of Finance[23].

Year 0 - 35 = 3.5%
Year 36 - 70 = 2.5%

The rate amounts to the sum of the risk-free rate plus a risk premium which is decreasing over time. This reflects the systematic, non-diversifiable risk. The socio-economic discount rate is decreasing over time. Project-specific risks (e.g. the risk of an unexpected increase in costs) are not included since they are assumed to be diversifiable across the Danish state's portfolio of projects.

The project-economic discount rate

The required rates of return of each respective project investors are summed to a weighted average. The weighted average cost of capital (WACC) is a common way to determine the required rate of return. It expresses, in a single number, the return that investors require to provide the company with capital. The WACC is likely to be higher if financed by stocks rather than debt since stocks typically carry greater risk. Thus, investors will demand greater returns in compensation.

Wind turbines: To estimate the required rate of return from the future owners of the wind turbines, the following input has been used; i) The capital structure, ii) the rate of return on equity, and iii) the rate of return on debt.

RoR on the equity portion: Based on the recommendations of the Danish Ministry of Finance[24] the real cost of equity investment from the future wind turbine owners has been estimated at 6.3%, assuming a real long-run risk-free rate of 2.2% and a beta value of 1[25].
RoR on the debt portion: Based on projections by the Danish Council for Return Expectations[26], the real risk premium on debt is 0.6% and 2.6% respectively, determined by whether the debt is assumed to be investment-grade bonds or high yield. Using the real risk-free rate of the Danish Ministry of Finance (2.2%), two cases for

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23 Danish Ministry of Finance (2021*). "Dokumentationsnotat for den samfundsøkonomiske diskonteringsrente*". Januar 2021. Link:https://fm.dk/media/18371/dokumentationsnotat-for-den-samfundsoekonomiske-diskonteringsrente_7-januar-2021.pdf

24 Danish Ministry of Finance/Finansministeriet (2021). *"Dokumentationsnotat for den samfundsøkonomiske diskonteringsrente".* Januar 2021. Link: https://fm.dk/media/18371/dokumentationsnotat-for-den-samfundsoekonomiske-diskonteringsrente_7-januar-2021.pdf

25 A beta of 1 implies that the capital stock in the project is as risky as the rest of the stock market – not more, not less.

26 The Danish Council for Return Expectations (2022). Link: https://www.afkastforventninger.dk/en/

the cost of debt exist: *a low cost of debt (2.8% real) and a high cost of debt (4.8% real)*[27].

Capital structure: Based on an analysis of the capital structures of three major offshore wind developers during the period 2015-2020 (Ørsted, RWE, and Vattenfall), a range is estimated: *A high debt case (80% debt and 20% equity) and a low debt case (60% debt and 40% equity)*.

The after-tax[28] WACC (required rate of return) calculated therefore lies within the span of 2.6-4.4% for the future wind turbine owners. Based on these calculations and supported by market dialogues, the WACC has been set to 4% in real terms.

Cable infrastructure: The required rate of return of the national, state-owned TSO, Energinet, which will own the infrastructure, is set to 5% which is equal to 3% in real terms, assuming a standard 2% inflation[29].

Energinet is assumed to own 100% of the cable infrastructure.

As a final remark, it is important to keep in mind that the required rate of return is closely related to risk. Therefore, the more risk mitigation, the lower the risk premium and thus the lower the required rate of return will be. Variations in the required rate of return and its impact on the project-economics is addressed in the sensitivity analysis section.

Uncertainties in the CBA

This section unfolds the substantial uncertainty in estimating the costs, benefits, and required rates of return as well as how they affect the profitability estimations.

In addition to uncertainties driven by general market- and price uncertainties when estimating power prices many years into the future, several central decisions regarding the design of the wind farms and the infrastructure still need to be made which in itself entails substantial estimation uncertainty. It should be noted that reference infrastructure investments of this dimension, size, and breadth of technical foresight in terms of future construction possibilities, are rare.

Estimation of the benefit side

In the following, power prices and the choice of estimation model are discussed.

[27] https://www.afkastforventninger.dk/media/1497/aendringer-i-afkastforventninger-2-halvaar-2022.pdf
[28] An assumed corporate tax rate at 22%. Source: Skat.dk (2022). Link: https://skat.dk/data.aspx?oid=2049049
[29] Energinet (2020): ***Energinets årsrapport 2019.*** Link: https://energinet.dk/om-nyheder/nyheder/2020/03/30/arsrapport-2019/

Power Prices

Estimations regarding future power prices are subject to great uncertainty driven by an unforeseen rate of development and an increase in supply and demand. We are already seeing signs of this in the past year's market price fluctuations. Thus, power prices cannot simply be extrapolated based on historical data.
The same logic is even more pronounced in the hydrogen market as we observe a rise in the use of electrolysis (supply) and an expansion in its potential uses (demand) which again is expected to increase rapidly, if and when production costs decrease.

In addition, the two markets may be considered two parts of a single market.
The future price of hydrogen affects estimates of the future demand of renewable energy in the form of PtX which in turn affects forecasts of future power prices. Assumptions regarding the hydrogen market, including assumptions about the future price of hydrogen, therefore have great influence. To capture this uncertainty, all results are presented in ranges according to whether a high or low hydrogen price development is assumed.

Another central assumption is the continuation of the current pricing mechanism in the power market, where power producers make a bid in the market based on their short-term marginal costs, and all producers receive the same power price. Reservations are therefore made for changes in the pricing mechanism in a future energy market characterised by a greater share of renewable energy.

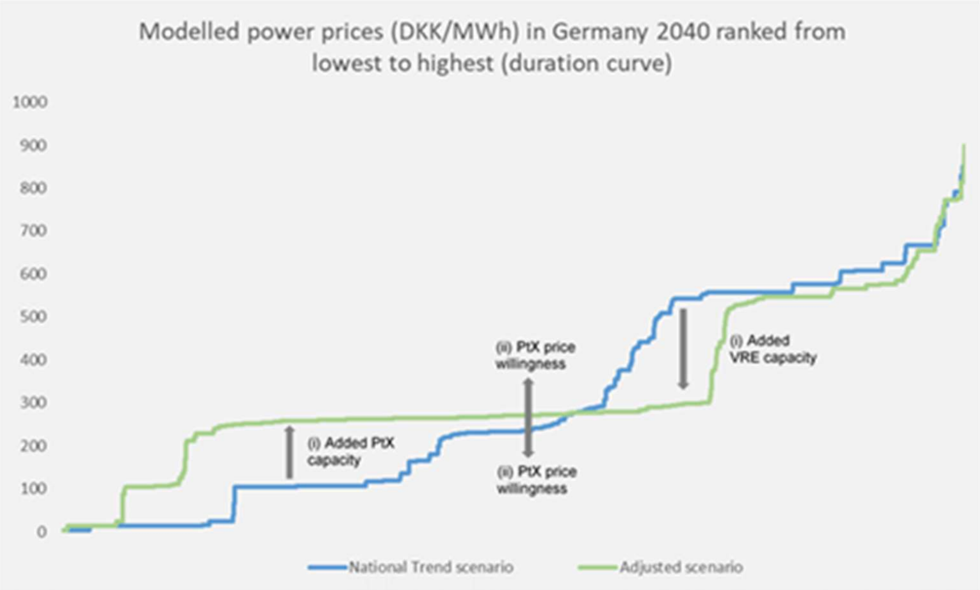
The modelling of the power price is explained by means of an illustrated example below. Figure 2 illustrates modelled power prices ranked from lowest to highest during the year's 8,760 hours in Germany in 2040. Two different scenarios are displayed by means of two staircase price curves; the blue line with the 'National Trend' (a) scenario and the green line with the 'adjusted' ENTSOE (b) scenario, prepared by DEA.

The original National Trend scenario (TYNDP20), without adjustments, leads to thousands of hours of prices below 200 kr./MWh. The National Trend scenario (TYNDP20) is based on the expected development of the power system towards 2040 back in 2018. Since 2018, there has been a significant development in the expectation of Europe's total electrolysis capacity, which is why the total electrolysis capacity in National Trends is far below expectations today. This is a significant shortcoming in National Trends, which does not harmonize with the current political announcements from the EU and a large number of member states. That fact makes the scenario considerably uncertain, especially in the long term where electrolysis is expected to play a significant role in the European energy system.
This observation has led DEA to update the scenario.

The differences between the two scenarios are driven by the following two factors:

1. how much PtX and correspondent renewable energy capacities are added
2. what the PtX owners' maximum power purchase price willingness is assumed to be

Figure 2: Modelled power prices



Source: Danish Energy Agency (2023)

The first factor reflects the level of PtX capacity assumed in the future power system in Europe. If the large-scale PtX capacity expansion announced by the European countries is to be realized, then a corresponding increase in the RE capacity is also required. The expansion of PtX capacity and renewable energy affects the power price-setting mechanisms. Assuming an increase in PtX, prices in low-price hours will increase, as PtX consumption generally is expected to take place during hours with low power prices, which will drive prices up in these periods. Additionally, as more renewable energy is added, prices will decrease in the middle to high price hours, as production increases without any new consumption from PtX (as prices are too high for PtX consumption).

The second factor reflects the PtX plants' willingness to pay, as the PtX producers are willing to purchase power up to a certain price level in order to be profitable. At power prices lower than this price level, the electrolysers will purchase and consume power. If the maximum power purchase price willingness increases, there will be an upward effect on power prices, as illustrated in figure 4. Vice versa, if maximum power purchase price willingness decreases, power prices will decrease.

Test of the robustness of the market forecast model

In addition to the electricity market modelling performed with RAMSES, the DEA has had the consultancy EA EnergiAnalyse perform additional energy system modelling with the Balmorel model. The Balmorel model employs a Long Run Marginal Cost investment model. When comparing the average weighted electricity prices faced by Danish offshore wind power with the results from the Balmorel and RAMSES models, the levels are almost the same. The insignificant difference between the Balmorel and RAMSES prices suggests that the two models give broadly similar results regarding the average weighted offshore wind prices. This strengthens the robustness of the results regarding the income side regardless of the choice of market forecast model.

Estimation of the cost side

In the following, commodity prices and the level of network reinforcements are discussed.

Commodity prices

Cost estimates from SWECO, Energinet, etc. are based on expected market prices in 2030[30]. The global market has faced substantial inflation in the past year, which has also resulted in higher cost estimates in this analysis. In fact, higher-than-average inflation has been observed in the RE market as we observe a global increase in both demand and ambitions for RE energy, including offshore wind. Given the relatively few manufacturers and hence the limited supply of the necessary technical facilities, we observe a significant price increase on e.g. particular cables and HVDC-converters.

Furthermore, the cost estimation is embedded with uncertainty since the necessary technical facilities are based on relatively unknown technology. There exist only a few relevant infrastructure projects of similar dimensions, size, and width in technical foresight regarding future facility opportunities. Therefore, there are only a few infrastructure projects to learn and draw inspiration from. This creates further uncertainty about the final costs of establishment until binding delivery contracts are signed.

Seabed conditions

Cost estimates are also affected by uncertainties regarding seabed conditions. Preliminary seabed analyses have indicated a need for further screenings and deep drillings to ensure that the seabed is sufficiently stable and has the needed load-bearing capacity. Unstable seabed conditions are a potential downside which can

[30] Prices are provided at a 2023-pl and then projected ahead, increasing by the rate of inflation (assumed to be stable in the long run at 2%).

lead to increased costs related to preventing erosion by securing the foundation. COWI has estimated that challenging seabed conditions at Danish sites can lead to a cost increase of 12-22% compared to sites with an unchallenging seabed[31].

Time-sensitive construction

Offshore construction by definition involves a degree of high uncertainty regarding planning, conditional on seasonal weather forecasts, availability with regards to limited amounts of specialist suppliers, immobile logistical equipment and technical personnel, and environmental concerns such as mating season. The high risk of needing to revisit plans and postpone complex logistical efforts e.g. six or twelve months with consequences for large amounts of resources and invested funds carry implied costs. Furthermore, the technology which is taken into account in the electrical infrastructure used on the energy island is to a large extent unprecedented in nature and scale. This only underlines the uncertainty of estimations.

The substantial uncertainty described in this section is accounted for by applying a risk premium on estimated costs. The next section covers the most important sensitivity analyses which help to understand the CBA impact of some of the most central variables.

Sensitivity analyses

One way to address the significant uncertainties in the CBA is by conducting sensitivity analyses to uncover the impact of changes on key variables. The results is addressed in a later section. The analyses shed light on the impact of a change in market prices, CAPEX, and the required rate of return.

Change in market prices

Sensitivity analyses with regard to changes in future market prices are conducted to test the robustness of results to the changes.

Changes in power prices are mainly driven by a combination of the following two factors:

(i) how much PtX (and correspondent VRE[32]) capacity is added and
(ii) the maximum power price the PtX owners are willing to purchase at.

While variations in the first factor (i) are accounted for in the four energy market approaches, the sensitivity analyses cover variations in the second factor (ii).

[31] COWI (2021). *"Cost benefit analyse og klimaaftryk af energiøer i Nordsøen og Østersøen"*. Januar 2021. Link: a209704-001_cost_benefit_analyse_endelig_version.pdf (ens.dk)
[32] Variable Renewable Energy

It is assumed that PtX plants will be willing to pay for power until the total production cost of producing hydrogen using grid power is at the same level as either producing hydrogen off-grid or importing it. Following this methodology as a way to determine the maximum average power purchase price willingness for an on-grid electrolyzer (the assumed type of PtX plant), particularly two factors have a large impact:

(i) The future cost/price of dedicated off-grid production or imported hydrogen (whichever is highest)
(ii) The future cost of using the grid (i.e. tariffs) for on-grid electrolyzers

The effect of these two factors on the maximum average power purchase price willingness is shown in table 7. Assuming an alternative hydrogen cost or import price of 140 DKK pr. GJ and tarifs of 50 DKK pr. MWh power (equivalent to 20 DKK pr. GJ hydrogen), the maximum average power purchase price for on-grid power will be 230 DKK pr. MWh, *cf. table 7*.

Changing these two assumptions has a significant impact on the estimated maximum average power purchase price willingness for on-grid power and consequently a significant impact on power prices.

Table 7

PtX plants' max. average power cost (DKK pr. MWh)

H2 cost off-grid/import (DKK pr. GI)	Tariffs (grid use) (DKK pr. MWh power)		
	30	50	70
160	302	282	262
140	250	230	210
120	199	179	159

Source: Danish Energy Agency

In order to account for the effect of both high and low tariffs and alternative hydrogen costs or import prices, sensitivity analyses have been carried out for power costs of 199 DKK pr. MWh, 230 DKK pr. MWh and 282 DKK pr. MWh. The table shows a range of power prices which are combinations of alternative hydrogen costs and tariffs that constitute best-case and worst-case scenarios seen from a consumer point of view. Given the current level of grid tariffs, a tariff of 70 DKK pr. MWh seems unrealistically high[33]. A worst-case tariff of 50 DKK has therefore been assumed.

[33] A tariff of 70 DKK pr. MWh is considered unrealistic since it would tend to indicate that the political opinion is that development of PtX is not to be incentivised, whereas the opposite opinion is being indicated by recent legislation and political resolutions.

The profitability estimations in the results section of this report are presented in ranges associated with an upper and a lower estimate of electricity price levels respectively.

Change in CAPEX

Sensitivity analyses with regard to changes in CAPEX are conducted to test the robustness of results to the changes.

A sensitivity analysis with a +/- spread of 10% from the central cost estimate is performed. 10% might seem low at first glance, but it should be taken into account that all CAPEX estimates already include a risk premium of 10%. Thus a variation of +/- 10% is considered realistic.

CAPEX sensitivity analyses are carried out for each of the four Baltic Sea scenarios (Baltic Sea 1-4). The results are presented in a separate section in this report.

Change in the required rate of return

Sensitivity analyses with regard to the required rate of return (WACC) are conducted as well.

Wind turbines: Changes to the WACC of the future owners of the wind turbines are driven by changes in the perception of risk and return. The required rate of return is also a derivative of the risk-free rate and is thus influenced by the overall market economy, in line with the price dynamics described above.

As described in the Methodology section, the after-tax[34] WACC (required rate of return) on the wind turbines is estimated at 2.6-4.4%. Based on this span, sensitivity analyses have been carried out for changes in the required rate of return to 3%, 4%, and 5% respectively.

Cable infrastructure & power systems: Since the required rate of return from Energinet's cable infrastructure is driven by the national revenue frame regulation for public entities and set by the Danish Utility Regulator, it is assumed constant. The sensitivity analysis therefore does not include changes in the required rate of return from the cable infrastructure.

The results of the sensitivity analyses of changes in the required rate of return are presented in a separate section in this report.

[34] An assumed corporate tax rate at 22%. Source: Skat.dk (2022). Link: https://skat.dk/data.aspx?oid=2049049

Cost-benefit estimations for Energy Island in the Baltic Sea

The following section covers the cost-benefit estimates for the Energy Island in the Baltic Sea. The section is structured as follows: (1) a detailed overview of the updated technical assumptions behind the current cost-benefit estimations, (2) an overview of the main findings regarding the politically accepted investment scenario 2 based on updated prerequisites, 3) a detailed presentation of the effects behind the main results, and (4) a walk-through of the main sensitivity analyses.

Updated technical assumptions

Different investment scenarios were presented in the summer of 2022. After it was politically decided to expand the capacity of the Energy Island in the Baltic Sea and to focus solely on realizing a 3GW solution in 2030, cf. *Tillægsaftale om Energiø Bornholm 2022* from 29. August 2022. Several assumptions have been altered in the cost-benefit estimations.

Updated budget reserves: Previous CAPEX estimates included varying levels of risk and reserve surcharges derived from different sources. To ensure uniformity in the application of risk and reserve surcharges, DEA has made the decision to apply the principles from "Ny Anlægsbudgettering (NAB)" across all CAPEX calculations, as described in the Methodology section. It should be noted, that in the original cost-benefit estimations, the estimates used in Energinet's §4-application were applied. The surcharge is now 10% across all investments. This has a positive effect on all scenarios.

Updated TSO cost split: An agreement between the German TSO 50Hertz and the Danish TSO Energinet has been signed. The agreement outlines that 50Hertz will finance approximately 3 billion DKK of the costs related to the facilities on Bornholm, corresponding to half of the total facility costs. In earlier profitability estimations this was estimated at 4 billion DKK. In addition, 50Hertz will finance the full cable from Bornholm to Germany. As a consequence of changes to the other before-mentioned technical assumptions, Energinet's estimated construction budget is reduced from 16.9 billion DKK to 13.9 billion DKK (excl. a 30% surcharge). Furthermore, Energinet's estimated operating costs will be reduced by 7 million DKK pr. year as this cost is also transferred to 50Hertz. This has a positive effect on all scenarios.

Updated OPEX for the offshore wind turbines: The operational costs related to the offshore wind turbines are now estimated to be 1.5% of the construction costs of the offshore wind turbines based on updated estimates from Sweco, as described in the Methodology section. This has a negative effect on all scenarios.

Updated market development approaches: Two additional approaches on how the European electricity market might develop have been added to the cost-benefit analysis since the summer of 2022. Previous calculations were based solely on the frozen policy approach (a) and the partially target consistent market approach (c), while the updated calculations also take into account the lower estimate for green transition approach (b) and the target consistent market approach (d).

Transmission availability: Prerequisites regarding transmission availability have been updated to assume an availability of 90% compared to the previous assumption of 100% availability. This has a negative effect on all scenarios.

Revenue from overplanting: Previous estimates did not include the value of potential revenues from overplanting. While the updated base scenarios for the Energy Island in the Baltic Sea still do not assume overplanting, the updated estimates of the need for a subsidy scheme assume 800 MW overplanting, which is the maximum capacity according to the completed assessment of the effects of the Energy Island on the environmental (SMV). This has a positive effect on the estimated need for a subsidy scheme in all scenarios.

Updated prices: All prices have been updated from 2021 prices to 2022 prices. This has a minor negative effect on all scenarios.

Inclusion of the sustainability package: Previous estimates did not include the cost of implementing sustainability measures in relation to the sustainability package initiative which was introduced by the Danish government in 2015. While the updated base scenarios for the Energy Island in the Baltic Sea still do not include costs related to the sustainability package, the updated estimates of the need for a subsidy scheme include costs amounting to 0.38 billion DKK. This has a negative effect on the estimated need for a subsidy scheme in all scenarios.

Main Findings: Investment scenario 2 incl. updated technical assumptions

The following section highlights the main findings regarding the politically agreed upon investment scenario 2 based on the updated technical assumptions. It elaborates on the findings for each of the four market approaches. This is done to be transparent and to highlight the potential pros and cons of the investment. Since it was decided to move on with investment scenario 2 – only this scenario is shown with updated assumptions.

Findings (revised baseline assessment)

Frozen policy (a): An updated socioeconomic impact of -17 billion DKK and a socio-economic project-economic impact of -26 billion DKK which is a worsening compared to -12 and -24 billion DKK from the previous profitability results, *cf. table 8*. Scenario (a) represents the lower span regarding the green transition of the Danish energy system and a “worst case” span for how the European energy system might develop if the RE capacity increases without a corresponding rise in the expected RE consumption.

A profitability assessment of the Energy Island in the Baltic Sea should not rely on the frozen policy scenario (a), since this scenario relies on older data and hence doesn’t account for more recent developments within climate- and energy policies (or that electricity demand is expected to follow the expansion of RE).

Lower estimate for the green transition (b): An updated socio-economic impact of -8 billion DKK and a socio-economic project-economic impact of -12 billion DKK. Previous estimates did not include the lower estimate for the green transition approach (b).

Partially target consistent (c): An updated socio-economic impact of -7 billion DKK and a socio-economic project-economic impact of -12 billion DKK, which is a reduction of the estimated socio-economic impact of about 5 billion DKK compared to previous estimates.

Target consistent (d): An updated socio-economic impact of -4 billion DKK and a socio-economic project-economic impact of -2 billion DKK, *cf. table 8*. Previous estimates did not include the target consistent approach (d).

The updated estimates shown in table 8 do not take into account the expected EU funding (about 1 billion DKK in the updated estimates).

The updated assumptions and the corresponding results presented in table 8 clearly suggests that profitability cannot be guaranteed for the investment of the Energy Island in the Baltic Sea.

Table 8

Socio-economic and project-economic impact of the Energy Island in the Baltic Sea (revised baseline assessment for the whole life span of 32 years).

	Updated cost-benefit estimation of 3 GW with a connection to DE in 2030	
DKKbn (2022 prices, net present value)	Socio-economics	Socio-economic project-economics
a) Frozen policy	Central estimate of -17	Central estimate of -26
b) Lower estimate for green transition	-16 to 4 w. a central estimate of -8	-21 to 0 w. a central estimate of -12
c) Partially target consistent	-16 to 4 w. a central estimate of -7	-20 to 0 w. a central estimate of -12
d) Target consistent	-12 to 8 w. a central estimate of -4	-11 to 10 w. a central estimate of -2
	Previous cost-benefit estimation of 3 GW with a connection to DE in 2030	
DKKbn (2022 prices)	Socio-economics	Socio-economic project-economics
a) Frozen policy	-12	-24
c) Partially target consistent	-11 to 9 w. a central estimate of -2	-18 to 2 w. a central estimate of -10

Note: It is not possible to generate a hydrogen span for the Frozen Politcy market approach (a).

Source: Danish Energy Agency (2023)

Supplementary profitability analyses

In the previous section, the investment is treated as an add-on investment. If instead it is assumed that the alternative to constructing an energy island is to construct radial offshore wind farms in the Baltic Sea, the analysis above should be supplemented with a cost-effectiveness-analysis: An analysis which estimates whether the Energy Island in the Baltic Sea is more profitable from a project- and socio-economic perspective compared to building radial offshore windfarms in approximately the same location, albeit with no interconnector.

Hence, DEA has conducted supplementary profitability calculations for the Energy Island in the Baltic Sea which estimate whether the Energy Island represents a cost-efficient solution for building offshore wind infrastructure by Bornholm, - i.e. as an alternative to the construction of radial wind.

The construction of the Energy Island in the Baltic Sea with offshore wind capacity of 3 GW in the partially target consistent scenario (c) is estimated to have a socio-economic impact of -5 to 9 billion DKK in the period of 2029-2062 compared to building radial offshore windfarms with equivalent capacity in the same location. Thus, there is an estimated possible positive gain in the base scenario. The estimated impact of each electricity market approach is elaborated upon below.

The estimated socio-economic project-economic impact is -16 to 6 billion DKK for the lower estimate for the green transition (b), while the socio-economic project-economic impact for the partially target consistent (c) market approaches amounts

to -17 to 5 billion DKK, *cf. table 9*. The estimated impact is improved to -9 to 13 billion DKK when applying the target consistent market approach (d).
The results of the updated estimates shown in table 9 do not take into account the expected EU funding which would be added to the total of about 1 billion DKK.

Table 9

DEA's supplementary profitability calculations, which treat the Energy Island in the Baltic Sea as an alternative to the construction of radial wind near Bornholm (revised baseline assessment for the whole life span of 32 years).

	Updated cost-benefit estimation of 3 GW with a connection to DE in 2030	
DKKbn (2022 prices, net present value)	Socio-economics	Socio-economic project-economics
b) Lower estimate for green transition	-3 to 10 w. a central estimate of 2	-16 to 6 w. a central estimate of -7
c) Partially target consistent	-5 to 9 w. a central estimate of 1	-17 to 5 w. a central estimate of -7
d) Target consistent	-5 to 8 w. a central estimate of 0	-9 to 13 w. a central estimate of 0
	Previous cost-benefit estimation of 3 GW with a connection to DE in 2030	
DKKbn (2022 prices)	Socio-economics	Socio-economic project-economics
c) Partially target consistent	1 to 15 w. a central estimate of 7	-14 to 8 w. a central estimate of -5

Note: The supplementary profitability calculations have not been carried out for the Frozen Policy market approach (a), since the amount of radial wind in this approach is not significant enough for it to be assumed that similar amounts of radial offshore wind farms would be established, should the Energy Island not be realized. The results do not take into account the expected EU funding which would be added to the total (about 1 billion DKK).

Source: Danish Energy Agency (2023)

It is further noted that the estimated gains would be significantly lower, if alternative radial offshore wind farms in the baseline scenario are not assumed to be located near Bornholm. The impact is reduced by about 9 billion DKK if the alternative radial offshore wind farms in the reference scenario are instead assumed to be located closer to Zealand. This means, that all estimated project and socio-economic impact ranges are lowered by 9 billion DKK compared to projects with a more optimal placements of 3 GW offshore wind.

The expected negative socio-economic project economics in the majority of the cost-benefit estimations reflect the possible need for a subsidy scheme of some kind. Common for both analyses is an upwardly adjusted estimate of the combined costs which reduces the socio-economic project economic net impact by about -2 billion DKK and the socio-economic net impact by about -5 billion DKK, *cf. table 10*.

Table 10

The summarised effect of the updated technical assumptions behind the profitability calculations (a comparison between previous and updated estimates)

	Updated cost-benefit estimations of 3 GW with a connection to DE in 2030	
DKKbn (2022 prices, net present value)	Socio-economics	Socio-economic project economics
Adjusted OPEX regarding wind turbines	-4	-4
Updated cost split btw. 50Hertz and Energinet	-2	-2
10% risk and reserve premium across all CAPEX estimates cf. NAB	+2	+2
Correction of out-time and cable availability	-2	-2
Updated model for the transfer of Energinet's costs	-	+3
Total	-5	-2

Note: Estimates including EU funding are, when rounded off, similar to estimates not including EU funding, and are therefore not included as separate estimates in the table.

Source: Danish Energy Agency (2023)

Estimated need for a subsidy scheme

Since the results of the CBA indicate that the future owners of the wind turbines will incur costs exceeding their revenues from power sales, estimates of the need for a subsidy scheme have been conducted for each of the four market approaches. It should be noted, that estimates of the need for a subsidy scheme are subject to great uncertainty and rely highly on, amongst other factors, uncertain estimates of power price levels and power supply and demand several decades into the future.

The estimated subsidy amount is presented in both fixed 2022 prices and net present value 2022 prices. The need for a subsidy scheme presented in fixed 2022 prices indicates the expected effect of the subsidy on the Danish Finance Act. Fixed prices are cleared for inflation and indicate the value of the needed support, seen in relation to the price level in 2022. In fixed prices, the estimated need for a subsidy amounts to between (-48) and (-10) billion DKK with a central estimate of -31.5 billion DKK when applying the partially target consistent market approach (c), *cf. table 11*. While the estimated need for a subsidy for the lower estimate for green transition market approach (b) is similar at -32.1 billion DKK, it rises to -58 billion DKK when applying the frozen policy market approach (a) and falls to -12.7 billion DKK when applying the target consistent market approach (d), *cf. table 11*.

The need for a subsidy presented in net present value 2022-prices indicate the future value of the subsidy when discounted back to 2022 in accordance with the involved partners' required return on investments. Future values are thus "worth less" in net present value prices than in fixed prices. In net present value, the estimated need for a subsidy amounts to between (-25) and (-5) billion DKK with a central estimate of -16.3 billion DKK when applying the partially target consistent market approach (c), *cf. table x*. While the estimated needed subsidy for the lower estimate for green transition market approach (b) is similar at -16.6 billion DKK, it rises to -30 billion DKK when applying the frozen policy market approach (a) and falls to -6.6 billion DKK when applying the target consistent market approach (d), *cf. table 11*.

Table 11

The estimated need for a subsidy scheme (incl. overplanting and sustainability package)

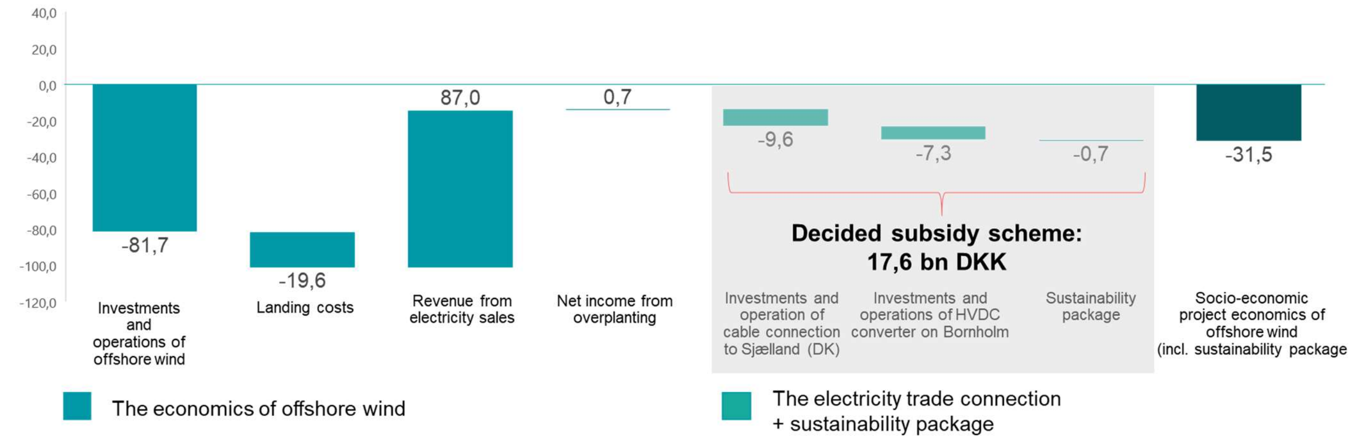
	Project-economics (negative values = need for a subsidy scheme)	
DKKbn (2022 prices)	Net present value	Fixed prices
a) Frozen policy	-30	-58
b) Lower estimate for green transi-tion	(-25) to (-5) w. a central estimate of -16,6	(-48) to (-10) w. a central estimate of -32,1
c) Partially target consistent	(-25) to (-5) w. a central estimate of -16,3	(-48) to (-10) w. a central estimate of -31,5
d) Target consistent	(-15) to (5) w. a central estimate of -6,6	(-29) to (10) w. a central estimate of -12,7

Source: Danish Energy Agency (2023)

The estimated need for a subsidy can be divided into costs that reflect 1) the economics of offshore wind and 2) the electricity trade connection from the Energy Island of the Baltic Sea to Zealand (DK) (since the connection to Germany is financed by Germany). The economics of the offshore wind cover the expected investments, operations, and landing costs to offshore wind farms of 101.3 billion DKK. The costs are partly compensated by the expected revenue from electricity sales and the net income from overplanting of 87.7 billion DKK. In addition, the need for a subsidy is mainly driven by net costs for the electricity trade connection to Zealand, which are transferred from Energinet to offshore wind, as well as a sustainability package.

Since the costs of offshore wind and the electricity trade connection are expected to exceed the revenues, the need for a subsidy is estimated to be 31.5 billion DKK in fixed prices in the partially target-consistent scenario. It has, however, been politically decided to place a cap on the subsidy scheme at 17,6 billion DKK which covers the costs of the electricity connection to Zealand and the converter on Bornholm as well as the costs to a sustainability package (see figure 3 below).

Figure 3: Breakdown of the estimated need for a subsidy scheme for offshore wind (fixed prices, billion DKK)



Source: Danish Energy Agency (2023)

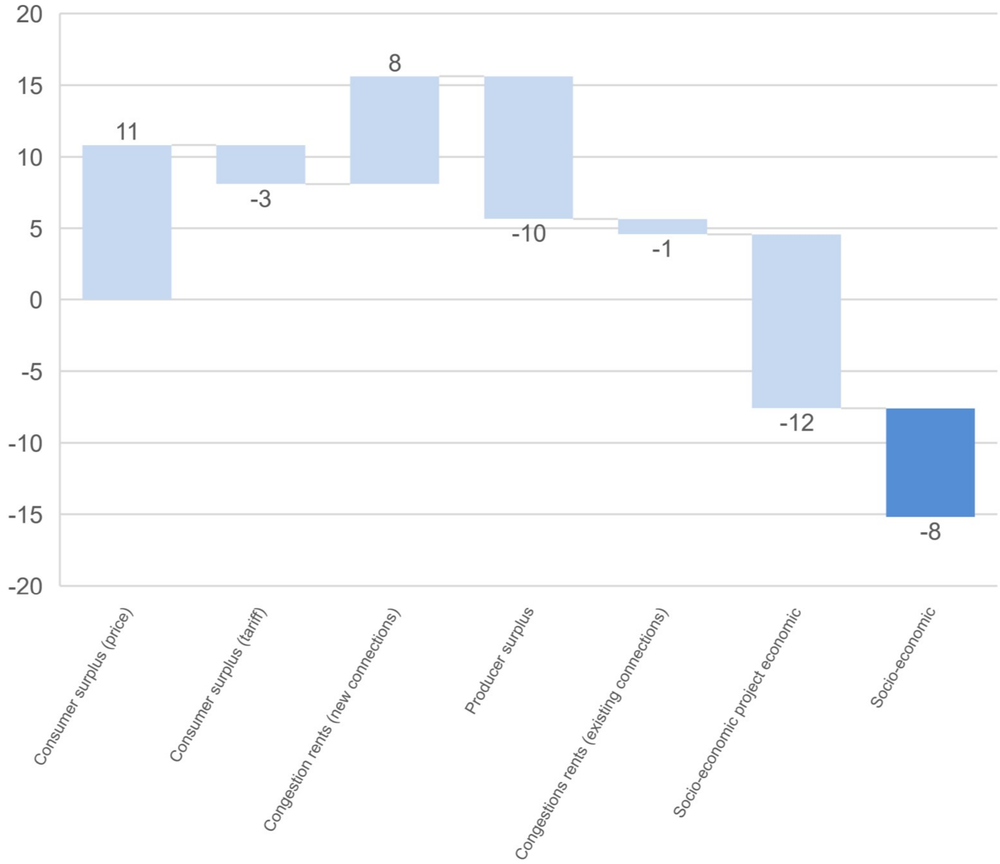
Presentation of the effects behind the main results

The following section presents the drivers behind each of the six baseline scenarios relevant to the Energy Island in the Baltic Sea. It should be noted that the estimates presented in these paragraphs are rounded to the nearest whole number, which might cause minor discrepancies when adding and comparing results across scenarios.

Socio-economic estimates for Baltic Sea 2, add-on, lower estimate for green transition (b)

Figure 4 highlights the sub-elements of the main socio-economic results for the Baltic Sea 2-scenario with the combined application of the add-on investment method and the lower estimate for green transition (b) approach.

Figure 4: Socio-economic estimates for Baltic Sea 2, add-on, lower estimate for green transition (b)



A price effect on the consumer surplus of 11 billion DKK: This scenario assumes that total power production increases significantly with the establishment of the Energy Island in the Baltic Sea adding a supply "shock" to the market equal to the GW installed on the Energy Island. This leads to a significant fall in power prices and thus a large consumer surplus.

Consumer tariffs effect on the consumer surplus of -3 billion DKK: Consumer tariffs rise, since only a certain share of Energinet's costs can be transferred to the owners of the wind turbines, and remaining costs are thus transferred to consumers via the tariffs. In this scenario, consumer tariffs rise by 3 billion DKK which results in a negative effect on the socio-economics.

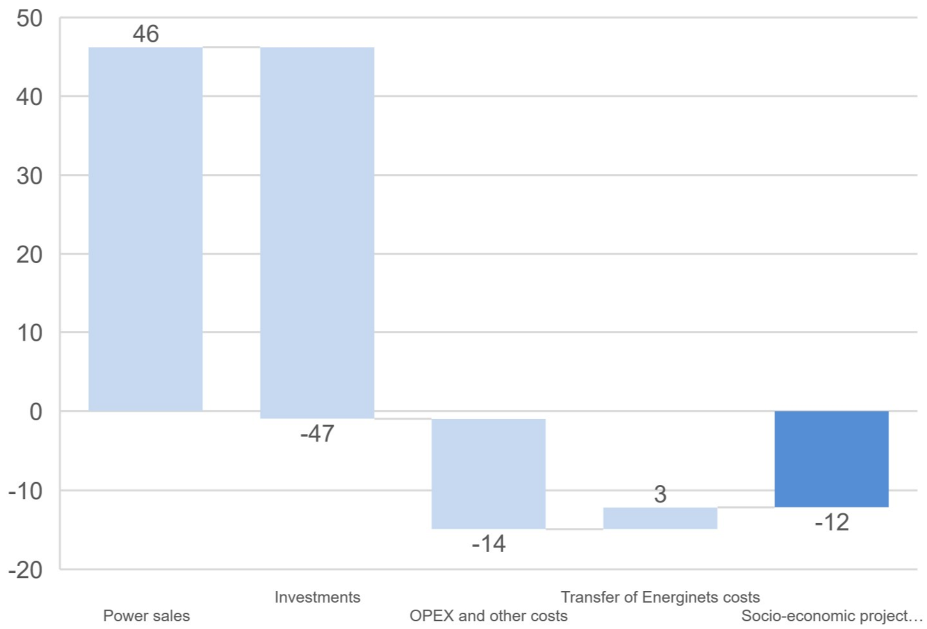
Congestion rents from new connections of 8 billion DKK: Congestion rents from the new cable connections to Denmark and Germany are estimated at 8 billion DKK. This estimate is driven by the expectation that the price level in the bidding zone on the Energy Island is lower than in the surrounding bidding zones – especially Germany.

A producer surplus effect of -10 billion DKK for existing producers: As previously described, the increased power supply created by the establishment of the Energy Island in the Baltic Sea is in this scenario not assumed to be followed by a corresponding increase in power demand. The increase in power production is therefore expected to lead to a fall in power prices creating a fall in producer surplus for existing power producers.

A reduction in congestion rents earned from the existing cable network of -1 billion DKK: Congestion rents from existing cable connections are expected to fall by -1 billion DKK. Power prices in the Energy Island's bidding zone are expected to fall with the establishment of the Energy Island, causing congestion rents from the surrounding existing cable connections to fall.

A negative socio-economic project-economic effect of -12 billion DKK excl. EU funding: The total project economy is estimated to reach a deficit of -12 billion DKK excl. EU funding. The following paragraphs describe the different project-economic elements leading to this result.

Figure 5: Socio-economic project-economic estimates for Baltic Sea 2, add-on, lower estimate for green transition (b)



Power sales of 46 billion DKK: Power sales from the Energy Island in the Baltic Sea to Denmark and Germany are in this scenario estimated at 46 billion DKK.

Investments of -47 billion DKK: The project-economic deficit is primarily driven by the cost of investments, in particular investments in power infrastructure, wind turbines, and cable connections to Denmark and Germany.

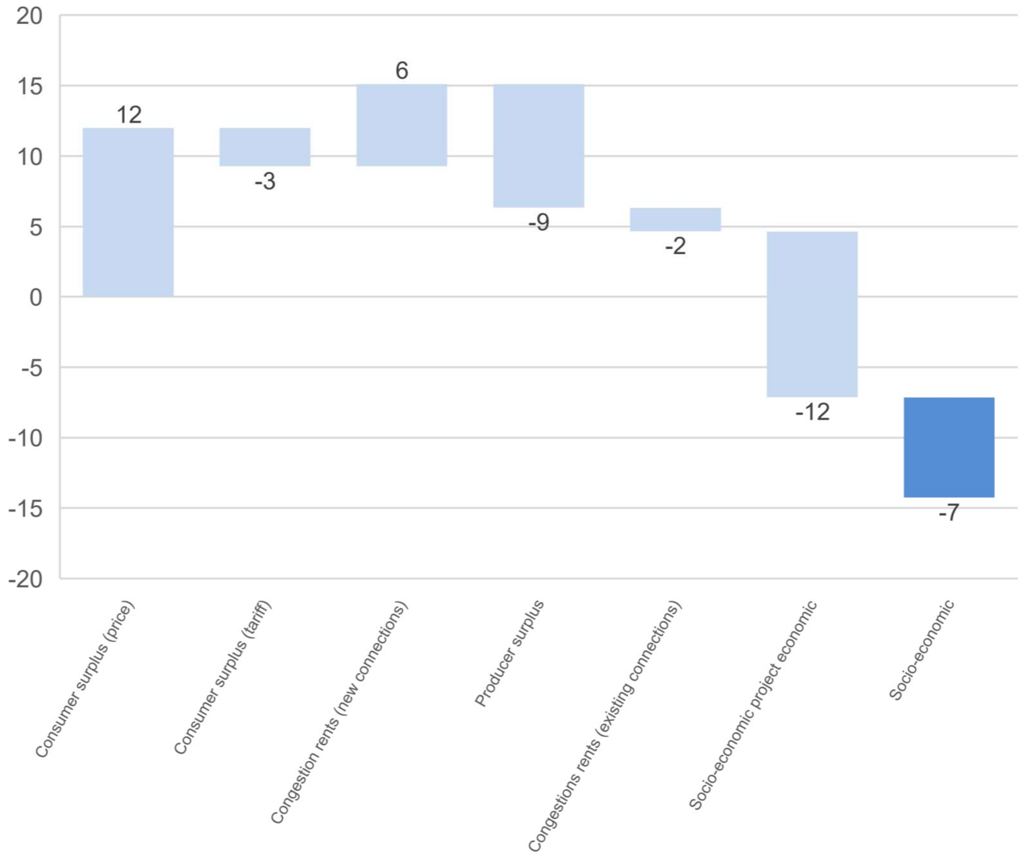
OPEX and other costs of -14 DKK: OPEX covers maintenance and repairs of power infrastructure, wind turbines, and cable connections etc. and is a fixed share of the corresponding CAPEX of each element. It furthermore covers costs of power loss during the transportation of power for which Energinet is liable.

Transfer of Energinet's costs of 3 billion DKK: As previously described, a share of Energinet's costs in the project scenario is transferred to consumers via consumer tariffs. Since this transfer has a distributional effect alone, the transfer only affects the project-economic estimates and does not have a net effect on the socio-economic estimates.

Socio-economic estimates for Baltic Sea 2, add-on, partially target consistent market approach (c)

Figure 6 highlights the sub-elements of the main socio-economic results for the Baltic Sea 2-scenario with the combined application of the add-on investment method and the partially target consistent market approach (c).

Figure 6: Socio-economic estimates for Baltic Sea 2, add-on, partially target consistent market approach (c)



Price effects on the consumer surplus of 12 billion DKK: Like the previous scenario, this scenario assumes that total power production increases significantly with the establishment of the Energy Island in the Baltic Sea adding a supply "shock" to the market. This leads to a significant fall in power prices and thus a large consumer surplus. It should be noted, that prices in this scenario are subject to a larger decrease than in the previous scenario. This difference may be caused by the fact that the partially target consistent market approach (c) assumes a larger European demand and production capacity, meaning that the market is to a larger extent "full" when the Energy Island is established. This means that the discrepancy in supply and the demand is larger which ultimately leads to a slightly larger price effect on Danish consumers.

Consumer tariffs effect on the consumer surplus of -3 billion DKK: Consumer tariffs rise, as would be expected, since only a certain share of Energinet's costs can be transferred to the owners of the wind turbines, and the remaining costs are thus transferred to consumers via the tariffs. In this scenario, consumer tariffs rise by 3 billion DKK which results in a negative effect on the socio-economics.

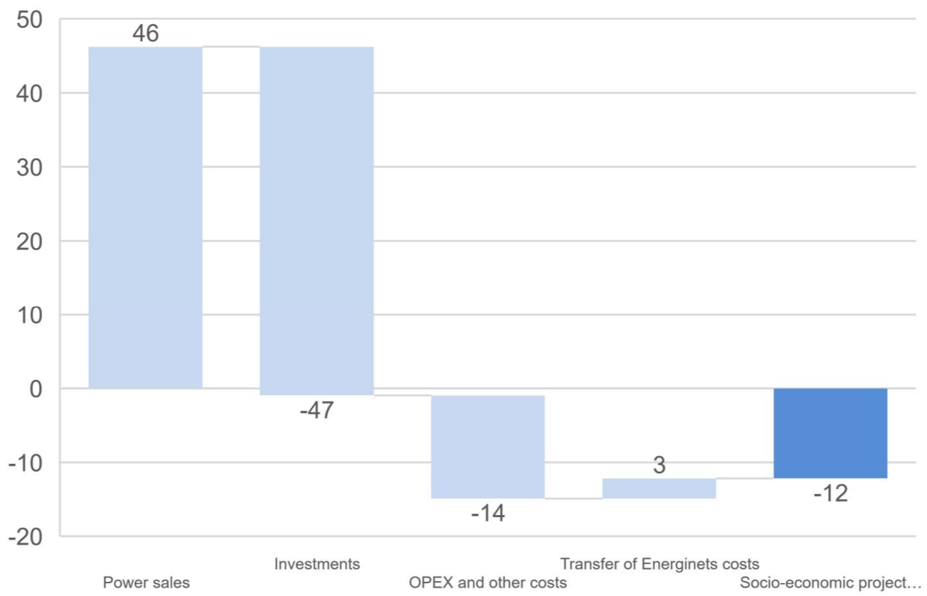
Congestion rents from new connections of 6 billion DKK: Congestion rents from the new cable connections to Denmark and Germany are estimated at 6 billion DKK. This estimate is driven by the price level in the bidding zone of the Energy Island expectedly being lower than the price level in surrounding bidding zones – especially Germany.

A producer surplus effect of -9 billion DKK for existing producers: As previously described, the increased power supply created by the establishment of the Energy Island in the Baltic Sea is in this scenario considered a supply "shock" to the market. The increase in power production is therefore expected to lead to a fall in power prices creating a fall in producer surplus for existing power producers.

A reduction in congestion rents earned from the existing cable network of -2 billion DKK: Congestion rents from existing cable connections are expected to fall by -2 billion DKK. As in the previous scenario, power prices in the Energy Island's bidding zone are expected to fall with the establishment of the Energy Island, causing congestion rents from the surrounding existing cable connections to fall.

A negative socio-economic project-economic effect of -12 billion DKK excl. EU funding: The total project economy is estimated to reach a deficit of -12 billion DKK excl. EU funding. The following paragraphs provide a description of the different project-economic elements leading to this result.

Figure 7: Socio-economic project-economic estimates for Baltic Sea 2, add-on, partially target consistent market approach (c)



Power sales of 46 billion DKK: Power sales from the Energy Island in the Baltic Sea to Denmark and Germany are in this scenario estimated at 46 billion DKK.

Investments of -47 billion DKK: The project-economic deficit is primarily driven by the cost of investments, in particular investments in power infrastructure, wind turbines, and cable connections to Denmark and Germany.

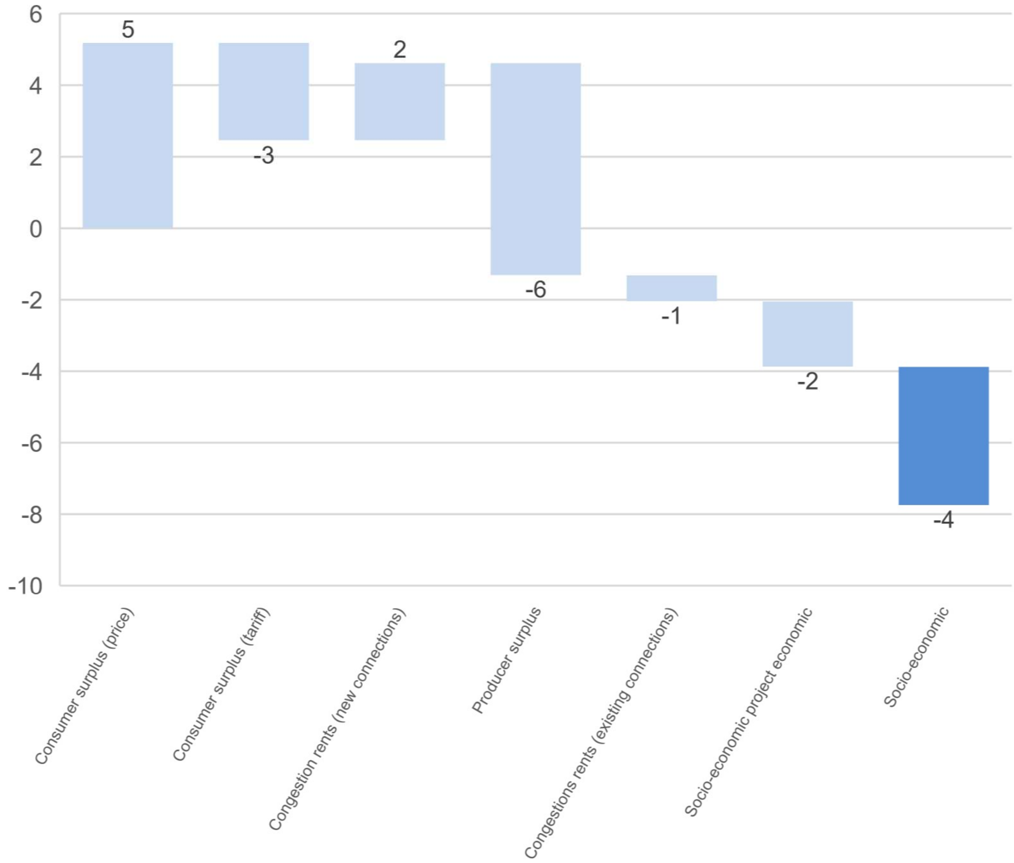
OPEX and other costs of -14 billion DKK: OPEX covers maintenance and repairs of power infrastructure, wind turbines, and cable connections etc. and is a fixed share of the corresponding CAPEX of each element. It furthermore covers costs of power loss during the transportation of power for which Energinet is liable.

Transfer of Energinet's costs of 3 billion DKK: As previously described, a share of Energinet's costs in the project scenario is transferred to consumers via consumer tariffs. Since this transfer has a distributional effect alone, the transfer only affects the project-economic estimates and does not have a net effect on the socio-economic estimates.

Socio-economic estimates for Baltic Sea 2, add-on, target consistent market approach (d)

Figure 8 highlights the sub-elements of the main socio-economic results for the Baltic Sea 2-scenario with the combined application of the add-on investment method and the target consistent market approach (c).

Figure 8: Socio-economic estimates for Baltic Sea 2, add-on, target consistent market approach (d)



Price effects on the consumer surplus of 5 billion DKK: Like the previous scenarios, this scenario assumes that total power production increases significantly with the establishment of the Energy Island in the Baltic Sea adding a supply “shock” to the market. This leads to a significant fall in power prices and thus a large consumer surplus.

Consumer tariffs effect on the consumer surplus of -3 billion DKK: As previously described, consumer tariffs are expected to rise, since only a certain share of Energinet’s costs can be transferred to the future owners of the wind turbines, and the remaining costs will therefore be transferred to consumers via the tariffs. As in the previous scenarios, consumer tariffs are in this scenario expected to rise by 3 billion DKK.

Congestion rents from new connections of 2 billion DKK: Congestion rents from the new cable connections to Denmark and Germany are estimated at 2 billion

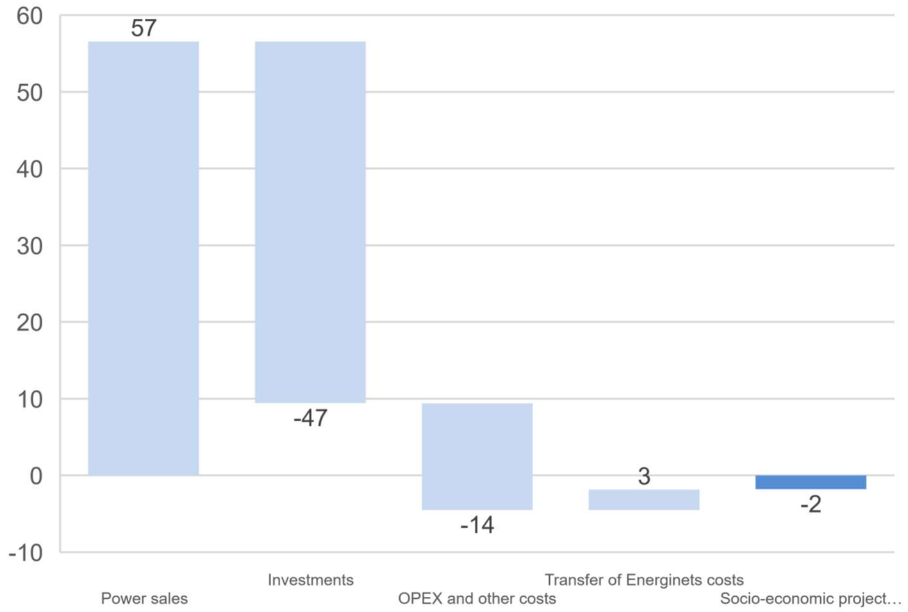
DKK. This estimate is driven by the price level in the bidding zone of the Energy Island expectedly being lower than the price level in surrounding bidding zones.

A producer surplus effect of -6 billion DKK for existing producers: As previously described, the increased power supply created by the establishment of the Energy Island in the Baltic Sea is in this scenario not assumed to be followed by a corresponding increase in power demand. The increase in power production is therefore expected to lead to a fall in power prices creating a fall in producer surplus for existing power producers.

A reduction in congestion rents earned from the existing cable network of -1 billion DKK: As in the previous scenarios, congestion rents from existing cable connections are expected to fall – in this scenario by -1 billion DKK.

A negative socio-economic project-economic impact of -2 billion DKK excl. EU funding: The total project economy is estimated to reach a deficit of -2 billion DKK excl. EU funding. The following paragraphs provide a description of the different project-economic elements leading to this result.

Figure 9: Socio-economic project-economic estimates for Baltic Sea 2, add-on, target consistent market approach (d)



Power sales of 57 billion DKK: Power sales from the Energy Island in the Baltic Sea to Denmark and Germany are in this scenario estimated at 57 billion DKK.

Investments of -47 billion DKK: The project-economic deficit is primarily driven by the cost of investments, in particular investments in power infrastructure, wind turbines, and cable connections to Denmark and Germany.

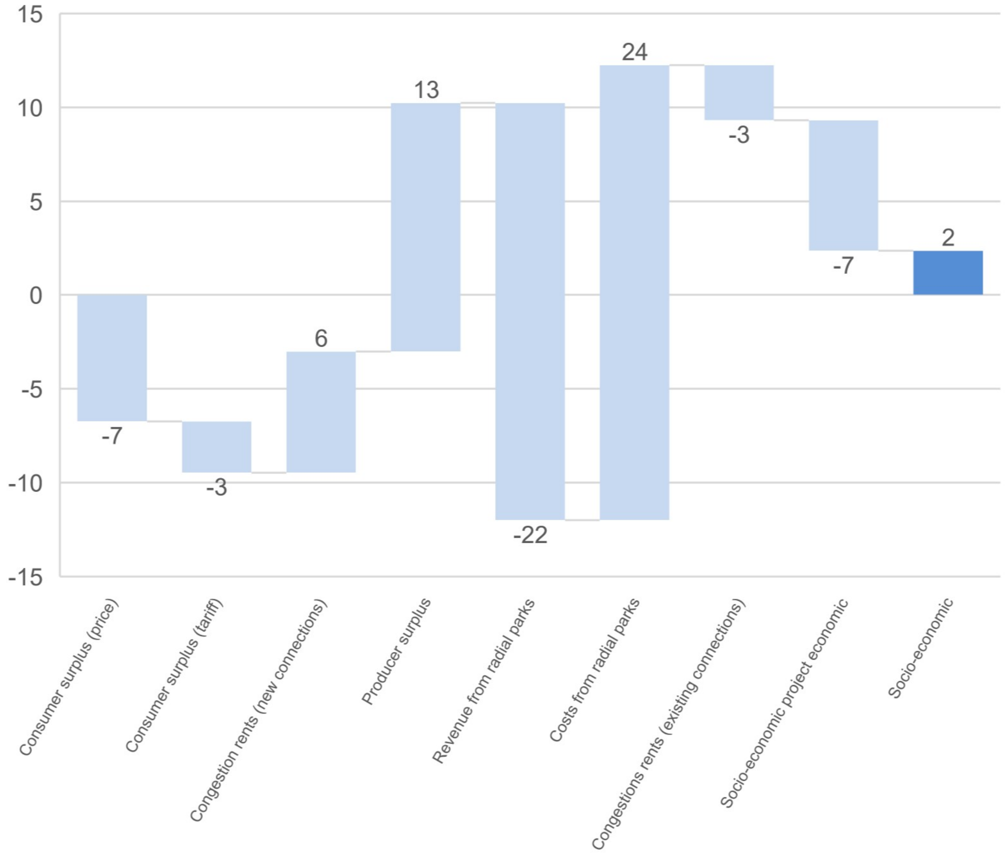
OPEX and other costs of -14 billion DKK: OPEX covers maintenance and repairs of power infrastructure, wind turbines, and cable connections etc. and is a fixed share of the corresponding CAPEX of each element. It furthermore covers costs of power loss during the transportation of power for which Energinet is liable.

Transfer of Energinet's costs of 3 billion DKK: As previously described, a share of Energinet's costs in the project scenario is transferred to consumers via consumer tariffs. Since this transfer has a distributional effect alone, the transfer only affects the project-economic estimates and does not have a net effect on the socio-economic estimates.

Socio-economic estimates for Baltic Sea 2, alternative to radial wind, lower estimate for green transition (b)

Figure 10 highlights the sub-elements of the main socio-economic results for the Baltic Sea 2-scenario with the combined application of the alternative to radial wind investment method and the lower estimate for green transition (b) approach.

Figure 10: Socio-economic estimates for Baltic Sea 2, alternative to radial wind, lower estimate for green transition (b)



Price effects on the consumer surplus of -7 billion DKK: In this scenario, establishing the Energy Island in the Baltic Sea results in an estimated loss for consumers in the form of a price rise of 7 billion DKK. This increase is caused by the establishment of a cable connection to Germany which increases flexibility and enables power producers to sell a larger share of power to Germany at a higher price than in Denmark. The power supply is therefore smaller in the project scenario than in the radial reference scenario, in which radial farms are connected via cable to Denmark only.

Consumer tariffs effect on the consumer surplus of -3 billion DKK: As previously described, consumer tariffs are expected to rise, since only a certain share of Energinet's costs can be transferred to the future owners of the wind turbines, and the remaining costs will therefore be transferred to consumers via the tariffs. As in the previous scenarios, consumer tariffs are in this scenario expected to rise by 3 billion DKK.

Congestion rents from new connections of 6 billion DKK: Congestion rents from the new cable connections to Denmark and Germany are estimated at 6 billion DKK. This estimate is driven by the price level in the bidding zone of the Energy Island which is expected to be lower than the price level in surrounding bidding zones. In this scenario, congestion rents from new connections are expected to be higher than in the previous scenario. This difference might be caused by the fact that general power price increases in Denmark create a larger price difference between the Energy Island bidding zone and the surrounding zones compared to the reference scenario. Furthermore, this scenario has a lower estimate for green transition (b) approach and thus assumes a smaller demand and production capacity than the previous scenario which was based on the target consistent market approach (d). This means that the market is to a smaller extent “full” when the Energy Island is established. The price difference between Germany and Denmark will thus be higher compared to the previous scenario, leading to more flexibility and lower prices for the wind turbine owners of the Energy Island and ultimately a larger expected price difference between the Energy Island and the surrounding bidding zones.

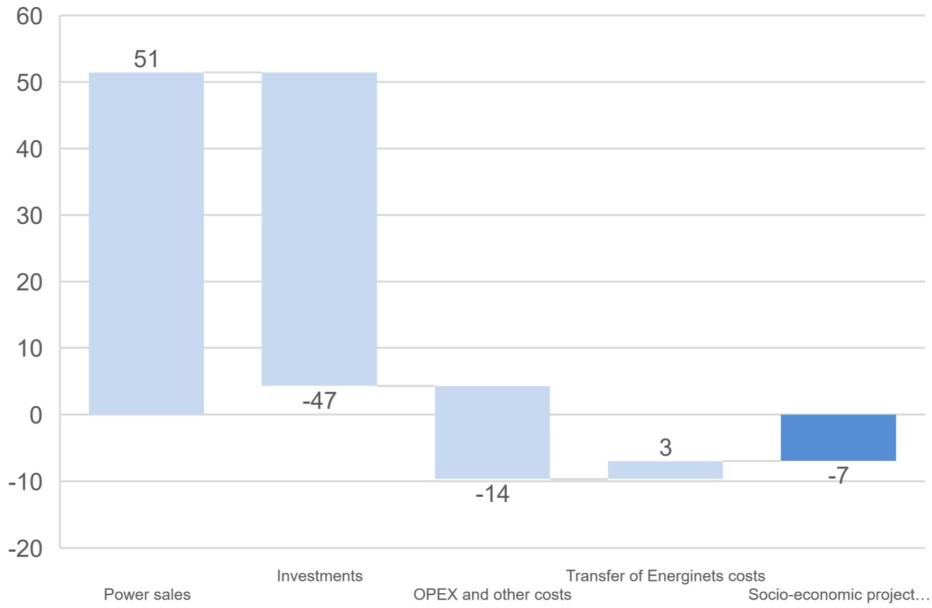
A producer surplus effect of 13 billion DKK for existing producers: Existing producers benefit from the establishment of the Energy Island, since it increases flexibility and enables power producers to sell a larger share of power to Germany at a higher price than in Denmark, and creates a corresponding decrease in power supply in Denmark. This benefits existing power producers positively.

Lost revenue from radial farms of -22 billion DKK and saved costs of 24 billion DKK: This scenario assumes that alternative radial offshore wind farms would be established, should the Energy Island in the Baltic Sea not be established. In the project scenario, these radial farms are replaced by the planned location of the energy island, and the revenue from the radial farms is thus lost. It is estimated that the alternative radial farms generate 22 billion DKK revenue in the reference scenario, all of which is lost in the project scenario. Similarly, the costs of building the alternative radial farms in the reference scenario are counted as a saving in the project scenario since no radial farms are built. These savings amount to an estimated 24 billion DKK which exceeds the lost revenue.

A reduction in congestion rents earned from the existing cable network of -3 billion DKK: As previously described, congestion rents are generated when Danish power prices are lower than power prices in surrounding bidding zones and countries. An increase in Danish power prices therefore leads to a decrease in congestion rents from existing cable connections. In this scenario, the establishment of the Energy Island leads to a general power price increase in Denmark, which leads to even bigger decreases in existing congestion rents than in the previous scenarios. This may be driven by the fact that assumed demand for RE is lower in this approach to the energy market than in (c) and (d). It is estimated that congestion rents from existing cable connections decrease by 3 billion DKK.

A negative socio-economic project-economic impact of -7 billion DKK excl. EU funding: The total project economy is estimated to reach a deficit of -7 billion DKK excl. EU funding. The following paragraphs provide a description of the different project-economic elements leading to this result.

Figure 11: Socio-economic project-economic estimates for Baltic Sea 2, alternative to radial wind, lower estimate for green transition (b)



Power sales of 51 billion DKK: Power sales from the Energy Island in the Baltic Sea to Denmark and Germany are in this scenario estimated at 51 billion DKK. Estimated power sales are worth more in this scenario than in the previous scenarios due to the previously explained expected increase in power prices compared to the reference scenario.

Investments of -47 billion DKK: The project-economic deficit is primarily driven by the expected 47 billion DKK cost of investments, in particular investments in power infrastructure, wind turbines, and cable connections to Denmark and Germany.

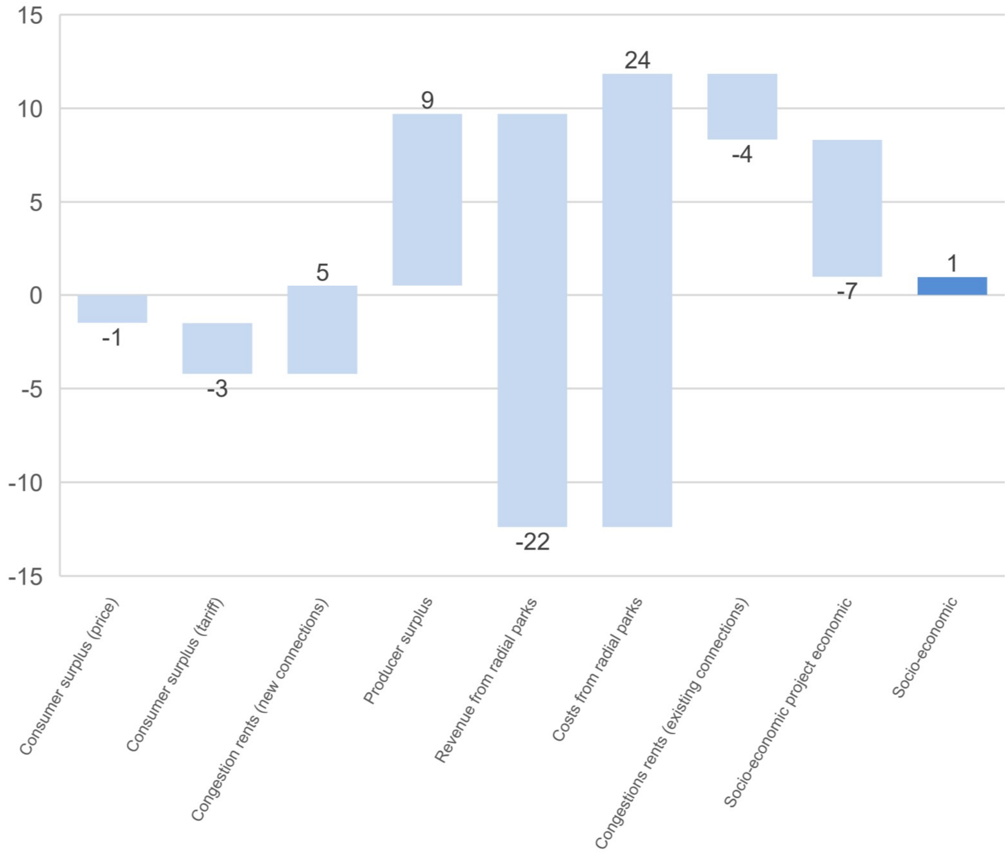
OPEX and other costs of -14 billion DKK: OPEX covers maintenance and repairs of power infrastructure, wind turbines, and cable connections etc. and is a fixed share of the corresponding CAPEX of each element. It furthermore covers costs of power loss during the transportation of power for which Energinet is liable.

Transfer of Energinet's costs of 3 billion DKK: As previously described, a share of Energinet's costs in the project scenario is transferred to consumers via consumer tariffs. Since this transfer has a distributional effect alone, the transfer only affects the project-economic estimates and does not have a net effect on the socio-economic estimates.

Socio-economic estimates for Baltic Sea 2, alternative to radial wind, partially target consistent market approach (c)

Figure 12 highlights the sub-elements of the main socio-economic results for the Baltic Sea 2-scenario with the combined application of the alternative to radial wind investment method and the partially target consistent market approach (c).

Figure 12: Socio-economic estimates for Baltic Sea 2, alternative to radial wind, partially target consistent market approach (c)



Price effects on the consumer surplus of -1 billion DKK: In this scenario, establishing the Energy Island in the Baltic Sea is estimated to lead to a loss for consumers in the form of a rise in prices of 1 billion DKK. As in the previous scenario, this increase is caused by the power supply being smaller in the project scenario than in the radial reference scenario due to the establishment of a cable connection to Germany. It should, however, be noted, that prices in this scenario are subject to a smaller increase than in the previous scenario. The explanation for this difference may be that the partially target consistent market approach (c) assumes a larger demand and production capacity, meaning that the market is to a larger extent “full” when the Energy Island is established. Prices will thus only be marginally higher in Germany than in Denmark, leading to a smaller negative price effect on Danish consumers.

Consumer tariffs effect on the consumer surplus of -3 billion DKK: As previously described, consumer tariffs are expected to rise, since only a certain share of Energinet’s costs can be transferred to the future owners of the wind turbines, and the remaining costs will therefore be transferred to consumers via the tariffs. As in the previous scenarios, consumer tariffs are in this scenario expected to rise by 3 billion DKK.

Congestion rents from new connections of 5 billion DKK: Congestion rents from the new cable connections to Denmark and Germany are estimated at 5 billion DKK. As with the previous scenario, this estimate is driven by the price level in the bidding zone of the Energy Island expectedly being lower than the price level in surrounding bidding zones. In this scenario, congestion rents from new connections are expected to be lower than in the previous scenario. This difference may be due to the smaller negative price effect on Danish power prices when applying the partially target consistent market approach (c), and thus smaller price difference between the Energy Island bidding zone and the surrounding zones compared to the reference scenario.

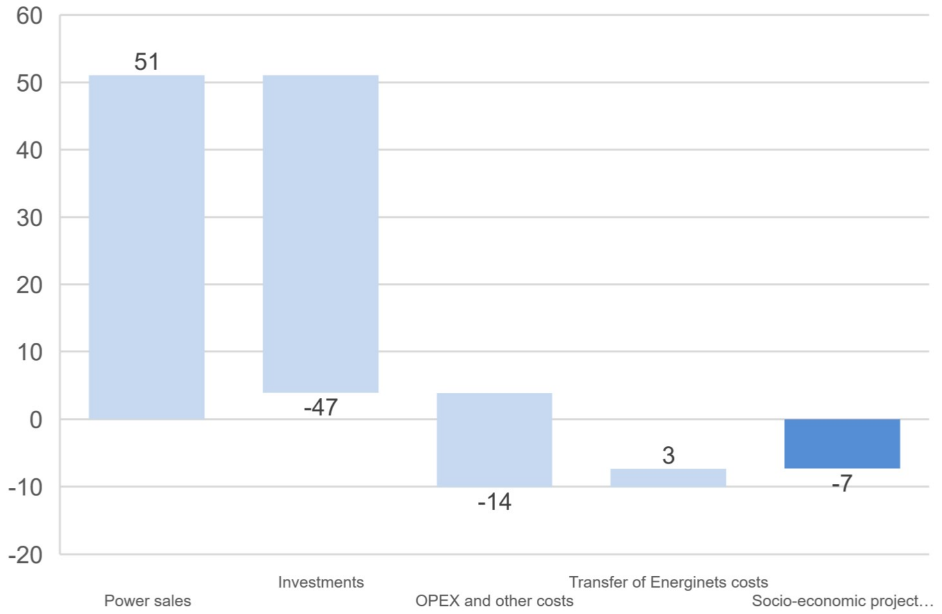
A producer surplus effect of 9 billion DKK for existing producers: As in the previous scenario, existing producers benefit from the establishment of the Energy Island, since it increases flexibility and enables power producers to sell a larger share of power to Germany at a higher price than in Denmark, and creates a corresponding decrease in power supply in Denmark. The effect is smaller than in the previous scenario which may be due to the decreased price effect in the partially target consistent market approach (c), as explained above in the paragraph regarding price effects on consumer surplus.

Lost revenue from radial farms of -22 billion DKK and saved costs of 24 billion DKK: As in the previous scenario, it is in this scenario assumed that alternative radial offshore wind farms would be established, should the Energy Island in the Baltic Sea not be established. Similarly to the previous scenario, it is estimated that the alternative radial farms generate a 22 billion DKK revenue and come with a 24 billion DKK establishment cost in the reference scenario, leading to a 22 billion revenue loss and a 24 billion cost saving in the project scenario.

A reduction in congestion rents earned from the existing cable network of -4 billion DKK: As in the previous scenario, an increase in Danish power prices is expected to lead to a decrease in congestion rents from existing cable connections. Furthermore, in this scenario the cable network is not developed to handle the assumed rise in activity – at least not to the same extent as in the previous market approach.

A negative socio-economic project-economic impact of -7 billion DKK excl. EU funding: The total project economy is estimated to reach a deficit of -7 billion DKK excl. EU funding. The following paragraphs provide a description of the different project-economic elements leading to this result.

Figure 13: Socio-economic project-economic estimates for Baltic Sea 2, alternative to radial wind, partially target consistent market approach (c)



Power sales of 51 billion DKK: Power sales from the Energy Island in the Baltic Sea to Denmark and Germany are in this scenario estimated at 51 billion DKK.

Investments of -47 billion DKK: The project-economic deficit is primarily driven by the expected 47 billion DKK cost of investments, in particular investments in power infrastructure, wind turbines, and cable connections to Denmark and Germany.

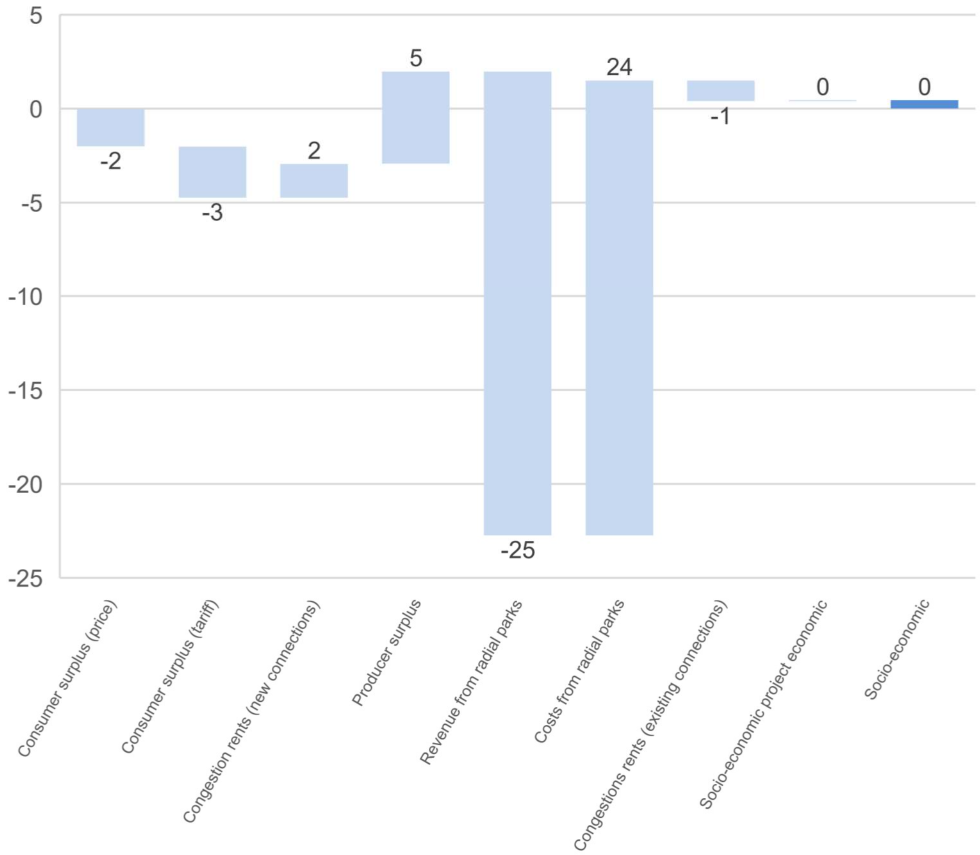
OPEX and other costs of -14 billion DKK: OPEX covers maintenance and repairs of power infrastructure, wind turbines, and cable connections etc. and is a fixed share of the corresponding CAPEX of each element. It furthermore covers costs of power loss during the transportation of power for which Energinet is liable.

Transfer of Energinet's costs of 3 billion DKK: As previously described, a share of Energinet's costs in the project scenario is transferred to consumers via consumer tariffs. Since this transfer has a distributional effect alone, the transfer only affects the project-economic estimates and does not have a net effect on the socio-economic estimates.

Socio-economic estimates for Baltic Sea 2, alternative to radial wind, target consistent market approach (d)

Figure 14 highlights the sub-elements of the main socio-economic results for the Baltic Sea 2-scenario with the combined application of the alternative to radial wind investment method and the partially target consistent market approach (d).

Figure 14: Socio-economic estimates for Baltic Sea 2, alternative to radial wind, target consistent market approach (d)



Price effects on consumer surplus of -2 billion DKK: In this scenario, establishing the Energy Island in the Baltic Sea is also estimated to lead to a loss for consumers in the form of a rise in prices of 2 billion DKK. As in the previous scenarios, this increase may be caused by the power supply being smaller in the project scenario than in the radial reference scenario due to the establishment of a cable connection to Germany. Since this scenario is based on the target consistent market approach (d), it assumes – like the previous scenario – a larger demand and production capacity than the lower estimate for green transition (b). This ultimately leads to a smaller negative price effect on Danish consumers.

Consumer tariffs effect on the consumer surplus of -3 billion DKK: As previously described, consumer tariffs are expected to rise, since only a certain share of Energinet's costs can be transferred to the future owners of the wind turbines, and the remaining costs will therefore be transferred to consumers via the tariffs. As in the previous scenarios, consumer tariffs are in this scenario expected to rise by 3 billion DKK.

Congestion rents from new connections of 2 billion DKK: Congestion rents from the new cable connections to Denmark and Germany are estimated at 2 billion DKK. As with the previous scenarios, this estimate is driven by the price level in the bidding zone of the Energy Island expectedly being lower than the price level in surrounding bidding zones. In this scenario, congestion rents from new connections are expected to be lower than in the previous scenario. A possible driver behind this difference is the fact that prices in the surrounding bidding zones are expected to be higher when applying the target consistent market approach (d), meaning that the difference in the price level between the Energy Island and the surrounding zones is smaller in this scenario than the previous scenario.

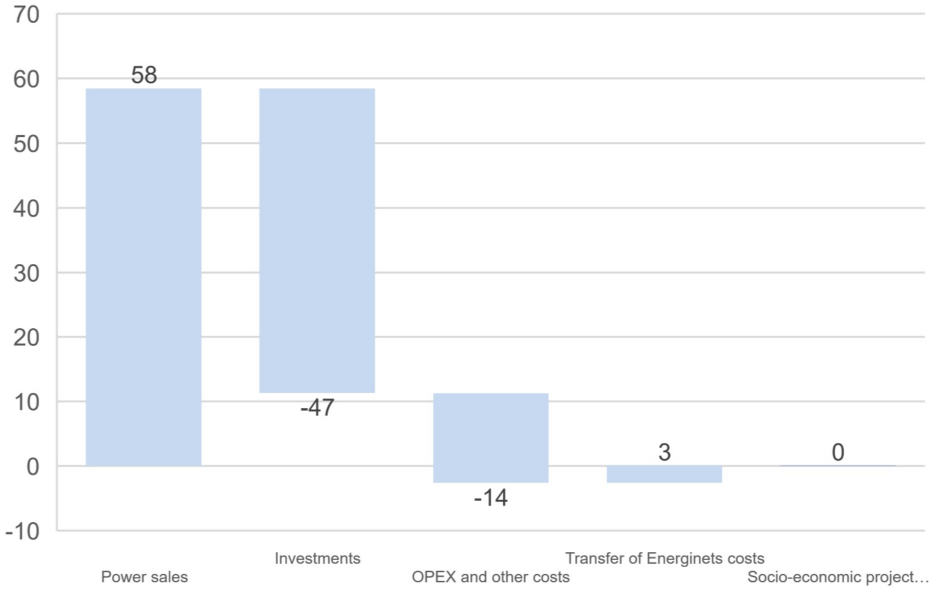
A producer surplus effect of 5 billion DKK for existing producers: As in the previous scenario, existing producers benefit from the establishment of the Energy Island, since it increases flexibility and enables power producers to sell a larger share of power to Germany at a higher price than in Denmark, and creates a corresponding decrease in power supply in Denmark. The effect is smaller than in the previous scenarios. This may be due to the decreased price effect in the target consistent market approach (d) compared to the lower estimate for green transition (b), as explained above in the paragraph regarding price effects on consumer surplus. Since the target consistent market approach (d) also assumes a larger demand and production capacity than partially target consistent market approach (c), this scenario ultimately leads to comparably smaller price effects than the previous scenario. This explains why the rise in producer surplus for existing producers is smaller in this scenario than in the previous scenario.

Lost revenue from radial farms of -25 billion DKK and saved costs of 24 billion DKK: As in the previous scenarios, it is in this scenario assumed that alternative radial offshore wind farms would be established, should the Energy Island in the Baltic Sea not be established. Similarly to the previous scenario, it is estimated that the alternative radial farms would cost 24 billion DKK to build in the reference scenario, which is counted as a 24 billion saving in the project scenario. In this scenario, the alternative radial farms in the reference scenario are expected to generate a 25 billion DKK revenue, which is counted as a loss in the project scenario. The 3 billion DKK increase in expected revenue might be explained by the assumption of higher RE demand and thus higher electricity prices in both Germany and Denmark in the target consistent market approach (d) compared to the partially target consistent market approach (c).

A reduction in congestion rents earned from the existing cable network of -1 billion DKK: As in the previous scenario, an increase in Danish power prices is expected to lead to a decrease in congestion rents from existing cable connections. Since the estimated price effect is lower in this scenario than in the two previous scenarios, the decrease in congestion rents from existing cable connections is only expected to reach -1 billion DKK.

A positive socio-economic project-economic impact of 0.5 billion DKK excl. EU funding: The total project economy is estimated at 1 billion DKK excl. EU funding. The following paragraphs provide a description of the different project-economic elements leading to this result.

Figure 15: Socio-economic project-economic estimates for Baltic Sea 2, alternative to radial wind, target consistent market approach (d)



Power sales of 58 billion DKK: Power sales from the Energy Island in the Baltic Sea to Denmark and Germany are in this scenario estimated at 58 billion DKK.

Investments of -47 billion DKK: The project-economic deficit is primarily driven by the expected 47 billion DKK cost of investments, in particular investments in power infrastructure, wind turbines, and cable connections to Denmark and Germany.

OPEX and other costs of -14 billion DKK: OPEX covers maintenance and repairs of power infrastructure, wind turbines, and cable connections etc. and is a fixed share of the corresponding CAPEX of each element. It furthermore covers costs of power loss during the transportation of power for which Energinet is liable.

Transfer of Energinet's costs of 3 billion DKK: As previously described, a share of Energinet's costs in the project scenario is transferred to consumers via consumer tariffs. Since this transfer has a distributional effect alone, the transfer only affects the project-economic estimates and does not have a net effect on the socio-economic estimates.

Sensitivity analyses for the Energy Island in the Baltic Sea

The following section covers the sensitivity of the CBA results for the Energy island in the Baltic Sea with regards to changes in i) electricity prices; ii) CAPEX and iii) the required rate of return.

Change in electricity prices

In the previous section on the main findings, the profitability estimations are presented in ranges - a lower estimate, a central estimate, and an upper estimate that indicate the results of electricity prices of 199 DKK pr. MWh, 230 DKK pr. MWh and 282 DKK pr. MWh, respectively.

The sensitivity of the estimated impacts with regard to the underlying power price dynamics is thus embedded directly in the profitability calculations. The observed result pattern shows that scenarios with lower power prices decrease both project and socio-economic profitability, and scenarios with a higher power price increase both project and socio-economic profitability. This is as would be expected.

Change in CAPEX

A sensitivity analysis with regard to changes in CAPEX is conducted to test the robustness of results to changes in costs and to accommodate the uncertainties related to estimating CAPEX as described in section in the methodology section.

A sensitivity analysis examining the effects of a +/-10% change in CAPEX is carried out for each of the Baltic Sea investment scenarios. A change in CAPEX will impact differently on each investment scenario, which is shown in *table 12.*

Table 12

Sensitivity analysis of the profitability effects of a +/-10% change in CAPEX

	Changes in CAPEX	
DKKbn (2022 prices)	10% higher CAPEX	10% lower CAPEX
Baltic Sea 1: 2 GW with 1.2 GW cable to DK and 2 GW to DE in 2030	-3	3
Baltic Sea 2: 3 GW with 1.2 GW cable to DK and 2 GW to DE in 2030	-4.6	4.6
Baltic Sea 3: 3 GW with 1.2 GW cable to DK and 2 GW to DE in 2030+2031 (stepwise)	-1.8	1.8
Baltic Sea 4: 1.2 GW with 1.2 GW cable to DK in 2030	-1.8	1.8

Source: Danish Energy Agency (2023)

All in all, the sensitivity analysis indicates that a reduction in CAPEX leads to an improvement of the socio-economic project-economics, and thereby the socio-economics, as expected. Vice-versa, an increase in CAPEX has a negative impact.

Change in the required rate of return

A sensitivity analysis with regards to changes in the required rate of return is conducted to test the robustness of results to changes in the discount rate and to capture a differentiated effect of the required rate of return on the project-economics.

As described in the methodology section, sensitivity analyses have been carried out regarding changes in the required rate of return on behalf of the owners of the wind turbines to 3%, 4%, and 5% respectively. The 4% required rate of return is used in the cost-benefit estimates presented above as the baseline estimate. Table 13 illustrates the estimated impact on project-economics measured in billion DKK when changing 4% down to a 3% or up to a 5% required rate of return.

Table 13

Sensitivity analysis of the profitability effects of a change in WACC

	Changes in the required rate of return		
DKKbn (2022 prices)	3%	4%	5%
Baltic Sea 1: 2 GW with 1.2 GW cable to DK and 2 GW to DE in 2030	1.9	0	-1.3
Baltic Sea 2: 3 GW with 1.2 GW cable to DK and 2 GW to DE in 2030	3.2	0	-2.2
Baltic Sea 3: 3 GW with 1.2 GW cable to DK and 2 GW to DE in 2030+2031 (stepwise)	3	0	-2
Baltic Sea 4: 1.2 GW with 1.2 GW cable to DK in 2030	-0.2	0	0.3

Source: Danish Energy Agency (2023)

For the majority of the Baltic Sea scenarios, there is a negative association between the required rate of return and the project-economic estimate, meaning that an increase in the required rate of return results in a lower project-economic estimate. This may be explained by the fact that if the future owner of the wind turbines has a higher required rate of return, all else equal, the investor will either be willing to pay less for the right to build or require more state funding to make the investment worthwhile (fixed earnings potential is assumed to illustrate this point).

For the Baltic Sea 4-scenario, there is a positive association between the required rate of return and the project-economic estimate, meaning that an increase in the required rate of return results in a higher project-economic estimate. This may be explained by the fact that the Baltic Sea 4-scenario doesn't include a connection to Germany, where power prices are on average higher, meaning that the isolated project-economic results for the future owners of the wind turbines are more likely to be negative in the Baltic Sea 4-scenario. This means that a lower required rate of return results in a smaller discounting of the potential deficit regarding the wind turbines, leading to a fall in the total project-economic estimate. Vice versa, a higher required rate of return results in a larger discounting of the potential deficit regarding the wind turbines, leading to a rise in the total project-economic estimate.

Conclusion

To conclude, the analyses shows that the results vary significantly when applying different assumptions across the analyses. The analyses indicate a risk that establishing the Energy Island in the Baltic Sea with a capacity of 3 GW in the year 2030 will not be profitable from neither a project-economic nor a socio-economic point of view.

For instance, the estimated socio-economic result varies with 13 billion DKK and the project-economic results varies with 24 billion DKK, across the four different scenarios for the future development of the European and Danish energy market, which are used in the analysis. As another example, the socio-economic result varies with 20 billion DKK, whether a high or a low future price on hydrogen is assumed. It also greatly affects the estimated results, how the renewable energy capacity of the energy island is assumed added to the baseline scenario. These significant variances in the estimated socio-economic and project-economic results obtained through different assumptions underline that all estimates presented in this report are subject to a high degree of uncertainty.

However, to inform the political process in the spring of 2023 on deciding, whether the project of establishing an Energy Island in the Baltic Sea should be realized, central estimates have been compiled, indicating that a socio- and project-economic loss seems more likely than a socio- and project-economic gain, considering the assumptions applied.

When applying the partially target consistent market approach (c) and the add-on investment method, while using varying assumptions on the future price of hydrogen, the results show a socio-economic impact varying from a loss of -16 billion DKK to a profit of 4 billion DKK. The socio-economic project-economic impact varies from -20 billion DKK to 0 DKK, which corresponds to an estimated need for a subsidy scheme ranging from 5 to 25 billion DKK in net present value or 10 to 48 billion DKK in fixed prices. While reflecting a central span of results with different assumptions concerning the future price of hydrogen, these results are still subject to a high degree of uncertainty, however it is relevant to highlight the results of this particular investment scenario, since:

- the partially target consistent market approach (c) is a central energy market approach applied in both the original and the updated CBA for the Energy Island in the Baltic Sea, and
- the add-on investment method is used as a baseline for the sensitivity analysis, as this is the main investment method applied in the cost-benefit analysis for the Energy Island in the Baltic Sea.

It should be noted that if the Energy Island in the Baltic Sea receives EU funding, the need for subsidies will be equivalently lower.

The results imply that regardless of the profitability assessments presented in this report, the establishment of the Energy Island in the Baltic Sea carries the risk of investments leading to a socio-economic and/or project-economic loss. Conversely, the establishment of the Energy Island in the Baltic Sea might lead to a socio-economic and/or project-economic gain regardless of the estimates presented in this report.

Finally, it is important to mention that this CBA only includes the value of quantified, monetary factors such as consumer surplus, producer surplus and congestion rents. Therefore, the CBA results do not take into account other possible monetary and societal benefits from the project. Therefore, possible upsides such as improved security of supply, possible revenue from PtX, saved costs from network reinforcements, and decarbonization of the Danish and European energy system are not reflected in the socio- and project-economic estimates from the CBA.