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Final Report

Study on an estimation method for the additional efficient operating expenditure of the Dutch TSO's offshore grid

Autoriteit Consument & Markt (ACM)

Authority for Consumers & Markets

Date: 23.12.2020

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About this document

Report Title:	Final Report
Project Name:	Study on an estimation method for the additional efficient operating expenditure of the Dutch TSO's offshore grid
Project Number:	10265331
Date of Issue:	23 December 2020

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Distribution:

☐ Unrestricted distribution (internal and external)
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☐ Unrestricted distribution within Customer contracting party
☐ No distribution (confidential)

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1 INTRODUCTION

The Dutch Government has adopted a development framework for offshore wind energy ("ontwikkelkader windenergie op zee") which sets the framework for the design, construction, availability and lifespan of the offshore grid in line with the Dutch offshore wind development targets. The Dutch government has appointed TenneT to construct and operate the offshore grid. The ACM is in charge of setting the allowed revenues for the offshore grid operated by TenneT and should determine a method based on which the allowed revenues for the offshore grid are to be calculated by the ACM for a regulatory period ("Methodebesluit net op zee").

The ACM has commissioned DNV GL to develop and evaluate different methods for estimating the additional (incremental) efficient operating expenditure (opex) that TenneT will incur with the commissioning of new parts of the offshore grid. The additional efficient opex have to be estimated for all parts of the offshore grid that will be commissioned between the 1st January 2021 and the 1st January 2027. Based on the development framework for offshore wind energy, the estimation therefore has to be prepared in relation to the grid connection and integration of the five Hollandse Kust offshore platforms for which a commissioning is planned in the abovementioned period. Incremental efficient opex in this context relate to efficient operating expenditure of TenneT which is expected to increase due to the commissioning of a new part of the offshore grid.

The report is structured as follows. Chapter 2 provides a short summary of the current regulatory framework in the Netherlands and a description of TenneT's current and planned future offshore grid in the Netherlands. The properties of the principal estimation methods are described in chapter 3. The next chapter (4) analyses the regulatory experience from other countries in relation to the estimation of offshore grid opex as well as the availability of international data. Chapter 5 sets out a set of criteria to be considered when developing such estimation method and defining its properties, reflecting the specific situation in the Netherlands and the availability of comparative data . The recommended approach and steps for the application of such estimation method are described in chapter 6. A quantitative estimation of the efficient offshore grid opex according to the recommended method provided for the regulatory period 2022-2026 is provided in the last chapter of this report in chapter 7.

2 CURRENT SITUATION IN THE NETHERLANDS

2.1 Regulatory Framework for the Regulatory Period 2017-2021

The allowed revenues of the onshore and offshore transmission grid of TenneT were subject to separate regulatory frameworks. In the regulatory period 2017-2021, a 5-year revenue-cap regulation with a static efficiency parameter (based on an international benchmarking of TenneT with other TSOs) and a dynamic efficiency parameter (accounting for a frontier shift, i.e. the efficiency improvement of all TSOs over time, including the most efficient one) were applied for TenneT's onshore electricity transmission network. The annual adjustment of allowed revenues (x-factor) of TenneT was calculated based on both efficiency parameters and inflation. The allowed revenues were set based on data from TenneT up until the year 2015. Additional capital and operational costs were added for onshore expansion investments conducted during the regulatory period. The following two types of expansion investments were defined for the regulatory period 2017-2021:

1. Regular expansion investments

2. Non-regular (i.e. specific) expansion investments.

For (1) the capital costs (depreciation and return on assets) were estimated based on the regular expansion investments in the three most recent years. For (2) the capital costs were added to the allowed revenue based on the actual capital costs. For both (1) and (2) the operational costs were calculated at 1% of (estimated or actual) capital costs (i.e. the total investment value before depreciation).

The allowed revenues of the offshore electricity grid of TenneT have also been subject to a 5-year revenue-cap regulation. For the regulatory period 2017-2021, however, no static or dynamic efficiency parameters were applied. This resulted in an x-factor equal to 0 so that allowed revenues are only adjusted for inflation on an annual basis using the consumer price index. Similar to the onshore provisions, additional capital and operational costs have been considered for offshore expansion investments conducted during the regulatory period. Initially, an opex allowance of 1% of capex for TenneT's offshore grid was adopted by the ACM for the 2017-2021 regulatory period. However, a court ruling has dismissed the application of this opex allowance, concluding that the estimation of efficient operating expenditure was insufficiently motivated. As a result of the court decision, TenneT was allowed to recover the actual opex for offshore assets for the current regulatory period. The offshore grid costs of TenneT were not recovered via the transmission network tariffs, but via a grant from the Ministry of Economic Affairs and Climate.

2.2 TenneT's Offshore Grid

All offshore wind farms that were commissioned before 2019 have their own individual electricity connection to the onshore transmission grid. These connections are not part of the Dutch transmission grid.[1] For wind farms commissioned since 2019, TenneT has been appointed by the Dutch government as the grid operator of the offshore grid connecting offshore wind farms with the onshore transmission grid. TenneT has been tasked with the development of the offshore grid in accordance with the timelines and design choices set out in the development framework for wind energy at sea. The development framework obligates TenneT to install and connect a total of eight offshore platforms with a capacity of 700 MW at alternating current (AC) each. Two of these offshore platforms have already been commissioned.[2] Five offshore platforms are planned to be commissioned by the end of 2026[3] and one additional offshore platform is planned to be commissioned in 2027.[4] In addition, two offshore platforms with a capacity of 2000 MW at direct current each are foreseen.[5]

The cable routes for the grid connections of the wind farms from the wind energy areas Borssele, Hollandse Kust (Zuid), Hollandse Kust (Noord) and Hollandse Kust (West, site VI) have already been

1 957 MW of offshore wind capacity have been connected under this framework (Gemini, Egmont aan Zee, Prinses Amalia and Luchterduinen) .

2 Borssele alpha (commissioned 31.8.2019) and Borssele beta (commissioned 31.8.2020).

3 The foreseen commissioning dates and connection pointes of the five AC offshore platforms are:
- Hollandse Kust Zuid alpha, commissioning expected 31-12-2021, connection point at Maasvlakte
- Hollandse Kust Zuid beta, commissioning expected 31-3-2022, connection point at Maasvlakte
- Hollandse Kust Noord, commissioning expected 31-3-2023, connection point at Beverwijk
- Hollandse Kust West alpha, commissioning expected Q1 2024, connection point at Beverwijk
- Hollandse Kust West beta, commissioning expected Q1 2026, connection point at Eemshaven, Burgum or Vierverlaten.

4 Ten noorden van de Waddeneilanden, commissioning expected Q1 2027, connection point at Beverwijk

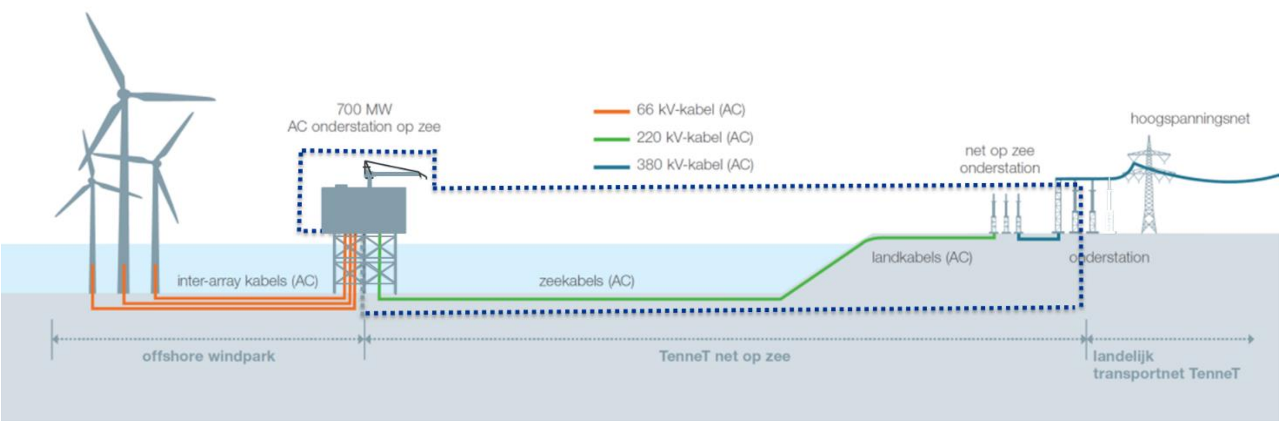
5 IJmuiden Ver alpha and beta expected to be commissioned in 2028 and 2029 respectively.

established. This is not the case for the connection locations and cable routes for the grid connections of the wind energy areas Hollandse Kust (West, site VII), Ten noorden van de Waddeneilanden and IJmuiden Ver (alpha and beta). There is, however, a selection of possible connection locations and routes.

Figure 1: Offshore grid roadmap until end of 2030[6]

A standardised identical design has been chosen for all scheduled AC platforms. The offshore grid consists of a platform at sea, a sea cable, a land cable and a transformer station on land.

Figure 2: Schematic diagram of the offshore grid[7]



6 Source: TenneT website

7 Source: Ontwikkelkader windenergie op zee versie voorjaar 2020

2.3 Regulatory Framework for the Regulatory Period 2022-2026

For the upcoming regulatory period 2022-2026, a new price control approach for electricity and gas transmission and distribution networks is currently being developed by the ACM. For TenneT's offshore electricity grid, the method decision contains two parts:

1) The first one refers to the estimation of the efficient costs for the years from 2022 to 2026 for the parts of the offshore grid that are commissioned before the 1st January 2021. This includes the costs of the Borssele alpha and Borssele beta platforms, general costs for the operation of the offshore grid, such as research and development costs as well as TenneT's overhead costs allocated to the offshore grid.

2) The second one refers to the estimation of the additional efficient costs for the parts of the offshore grid that are commissioned between the 1st January 2021 and the 1st January 2027. This includes the five platforms Hollandse Kust Zuid (alpha and beta), West (alpha and beta) and Noord, which are scheduled to be commissioned after the reference date and before the end of the upcoming regulatory period.

The remuneration of the efficient cost of the offshore grid related to these platforms is determined by the ACM on a yearly basis at the end of the year before their commissioning. The capital costs included in the allowed revenue (depreciation and return on assets) are set on the basis of planned capex figures and then adjusted based on the actual figures and efficiency assessment. The efficiency of the offshore grid capex will be assessed ex-post on an individual project basis. The estimation of the additional efficient operating expenditure that is to be added to the allowed revenues of TenneT, when a new part of the offshore grid is commissioned, is the subject of this study.

3 PRINCIPAL METHODS FOR COST ASSESSMENT

Operational expenditures (opex) are costs incurred by network operators to maintain and operate network assets necessary to provide regulated services. The recovery of opex does not provide any return to the regulated business as it is paid out in the form of expenses like salaries, materials and services. For the purposes of revenue setting, regulated companies receive an allowance for the duration of the regulatory period. The regulator should recognise the importance to the companies in recovering a sufficient level of opex. At the same time, it is important that network operators are not allowed to recover excessive or unnecessary costs in providing their services.

Regulatory authorities can use bottom-up methods or top-down methods to set the allowed opex. When analysing the characteristic properties of different regulatory models, it is important to note that while the theoretical concepts may provide different types of incentives, these differences may be less pronounced in practice. This is mainly because the regulatory models are rarely applied in their pure form and often contain elements of different regimes simultaneously, i.e. a combination of methods.

This chapter provides an analysis of the methods including their economic properties. Furthermore, it highlights some specific aspects related to cost setting (aggregation level, periodicity, indexation).

3.1 Top-Down Analysis

Top-down methods set opex with reference to the allowed cost for broad (aggregated) opex categories. The determination of the reasonable cost level can be informed by external comparators ranging from a simple partial performance analysis to more complex multi-dimensional methods based on parametric and non-parametric analysis assessing efficiency regarding several inputs (typically costs) and outputs.

Non-parametric methods, such as the Data Envelopment Analysis (DEA) methodology, determine an efficiency frontier by linear combinations of the best performing companies in the sample. Parametric approaches use econometric techniques to estimate the functional relationships between inputs and outputs. Both groups of methods require sufficient, reliable and comparable data. It will not be possible to apply top-down methods if there is insufficient data. Furthermore, the results of top-down analysis are sensitive to the quality of input data and will be inaccurate if the data quality is not assured. The benefits and usability of the analysis are greatly dependent on the data consistency. This is particularly relevant for offshore grid connections, where comparisons with other companies can generally only be done on an international level.

In the process of target setting, regulators may also decide to consider the company's historic performance, using information on recent levels of performance, and longer-term trends in improvement. This however also requires the availability of sufficient data on the historic performance.

3.2 Bottom-Up Analysis

Bottom-up methods consist of splitting the relevant costs by item and then assessing these items individually.

The scrutiny can range from using a "model" company to an engineering/technical analysis of main relevant activities for provision of regulated services. The former approach relies on the definition of a model company by building up the inputs and costs in a 'bottom-up' manner which essentially implies the creation of a production function. Data for the regulated company is then used in the production function to determine the overall appropriate cost level for the company.

The bottom-up activity analysis involves assessing business processes to determine the scope for performance improvement. Accordingly, the cost drivers used by the bottom-up analysis are on activity level / workload. Such cost drivers can exhibit endogeneity issues if the investigated company has some control over a cost driver. For example, the level of maintenance activity can be a reflection of external requirements as well as decisions taken by the company as to how its regulated network assets should be maintained. Since some decisions are not fully exogenous, they may present incentive problems.

To overcome this issue, in practice the cost driver on activity level / workload can be set with reference to industry norms or expert judgements. Furthermore, if data is available it can be supported by targeted comparisons of individual cost items among different operators (elements of top-down approach), the development of cost items over time, or the comparison of cost items with general industry trends or market prices. The allowance is set with reference to the allowed expenditures for individual cost items or related activities. These are then added together to produce the total allowance.

Bottom-up analysis does not entirely rely on the actual efficiency of other companies or historic company data to determine efficiency and in this way reduces regulator's reliance on cost information provided by companies. The analysis can lead to a more precise and detailed assessment of the individual cost items. To the extent that it relies on engineering judgements, the results of bottom-up analysis could potentially be influenced by subjective views on the efficiency of individual cost items. As the approach is data intensive, it can require significant resources and result in a relatively high administrative burden.

3.3 Further Relevant Aspects

3.3.1 Opex Disaggregation

The cost performance can either be assessed at aggregated or disaggregated level. Assessment at the disaggregated level involves a separate assessment of individual opex categories before they are added together to obtain total allowances. Alternatively, the cost performance can be assessed in aggregate, i.e. by an assessment of the total opex.

The aggregated approach is often observed in the context of a comparative top-down analysis while the disaggregated one is observed in bottom-up studies. However, comparative assessments are also applied at partially aggregated or disaggregated level where opex is individually assessed for business activities.

In principle, by abstracting from individual cost items, an aggregated approach can help to avoid issues arising from the complexity of the cost boundaries, such as differences in cost data reporting, activity definitions etc. which are more visible in disaggregated assessments. Further reasons to group activities and expenditures in the assessment process may relate to their complementarity and existing trade-offs. If the company can make trade-offs in expenditure between the different activities/areas included in aggregated cost blocks, assessing those activities/costs together can help avoid biased relative efficiency results or unintended managerial incentives. Based on these points the cost aggregation can be considered as part of the benefit of adopting a top-down approach.

However, in deciding which business support activities to assess on an aggregated level and which activities may need individual assessments, regulators need to be mindful of the risks of inconsistency across activities. In addition, the aggregation may be result in a loss of precision. Disaggregated cost assessment models with a higher degree of granularity may be possible to better identify cost drivers that reflect the specific costs under consideration. Consequently, such models may help to more accurately reflect the individual conditions within the context of cost performance, which more aggregated models may struggle to achieve.

Regulatory authorities often apply explicit arrangements for electricity network losses incorporating a separate cost allowance into the allowed revenue. These schemes are based on physical loss targets set in absolute terms or as a percentage of the electricity volume delivered to the electricity networks.[8] The allowed physical losses are monetised through a reference price, reflecting the cost of purchasing energy to cover network losses which can take place on power exchanges or bilaterally. When separate targets or sharing mechanisms are to be applied for network losses, a separate estimation of the costs of network losses also needs to be conducted ex-ante (i.e. separate from the general opex allowance).

3.3.2 Periodicity

One option is to use a single figure based on the average opex figure reflecting the efficient opex that will be incurred for the specific asset group over its lifetime. Alternatively, averages of the efficient opex arising over the duration of a regulatory period can be applied. Maintenance costs of specific assets may for example occur at certain intervals, linked to the foreseen frequency of the underlying maintenance activities. Furthermore, opex may vary over the lifetime of an asset, reflecting initial costs at the start of operation and cost arising at the end of the lifetime of an asset. Initial costs could for instance be higher

8 In such cases the allowed losses are determined as being a product of the allowed percentage losses set by the regulatory authority and the electricity volume delivered to the electricity network.

due to training and learning activities, but could also be lower, if the failure of assets and equipment in the initial phase is still covered by a warranty of the according manufacturer. Cost arising at the end of the lifetime of an asset may possibly be influenced by increasing maintenance costs or even decommissioning costs. Depending on the specific duration over which the opex allowance is determined, this could possibly result in significant changes in the level of the allowance from one regulatory period to another or to increases in the allowance over time. Bottom-up approaches do in principal allow to explicitly consider periodicity, i.e. reflecting the costs that arise at the point of lifetime of the underlying assets in the period for which the allowance is set, especially when industry norms or expert judgements are applied. This is particularly relevant when an allowance is set for a small sample of assets, such as a limited number of offshore grid connections, whose costs vary significantly over time.

3.3.3 Indexation

The regulatory approach for the determination of the opex allowance should be set for the duration of the regulatory period. One way of setting the opex allowance in Euro for every year of the regulatory period is to base it on an explicit ex-ante cost assessment for the respective calendar year of the regulatory period. The advantage of this approach is that it would be able to reflect step changes in the annual cost levels. The disadvantages are mainly related to the required higher administrative burden. Furthermore, this approach would also require an ex-ante specification of the precise date of commissioning.

Alternatively, the allowances could be set ex-ante in relation to the year of commissioning, estimating the efficient offshore grid opex for year 1, 2, 3, etc. following the commissioning of an individual grid segment. This would also allow step changes to be applied while the precise date of commissioning of an individual offshore grid connection does not need to be specified ex-ante.

A possible third option is to set the opex allowance based on an average value of opex per year for the duration of the regulatory period (either per platform or across all platforms expected to be commissioned).

The opex allowance can be expressed in nominal terms (already considering expected inflation) or in real terms. In the latter case, the opex should be explicitly indexed for inflation. The indexation scheme can also incorporate additionally specific incentive terms related to efficiency improvements.

Regulators typically use a measure of economy-wide inflation such as the Consumer Price Index (CPI) or the Retail Price Index (RPI). The primary advantage of such inflation indices is that they are easily and transparently observable. Such measures are perceived as objective as they are regularly computed and published by respected government agencies. The main concern is that economy-wide price inflation may not reflect price trends for inputs purchased by the regulated companies in the specific case.

4 ANALYSIS OF REGULATORY EXPERIENCE FROM OTHER COUNTRIES

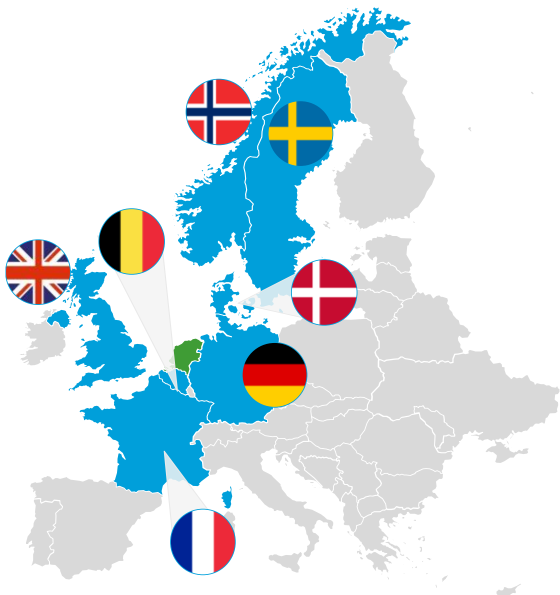
While significant offshore wind capacities have been planned in several countries, many of these projects are still being in an early consideration and planning phase. Actual offshore wind generation is only in operation and connected to the electricity grid in a few countries. In a number of countries, actual offshore wind generation also only relates to (smaller) pilot projects or to near-shore offshore wind generation, whereas the connection of individual offshore wind farms with the electricity transmission network is considered to be a network connection and not part of the transmission network infrastructure. Consequently, only a few countries have already implemented an explicit regulation in relation to the cost of offshore grids. Out of these countries, even a smaller number of regulatory jurisdictions have adopted a regulatory procedure and methodology for the estimation of efficient offshore grid opex. In the following section we provide an overview of the regulatory approaches applied in other countries (section 4.1) and discuss the available international data (section 4.2).

4.1 Overview of Regulatory Approaches

Offshore wind farms in different countries are built or planned at various distances to the shore, water depths and ground conditions. Moreover, the connections to the onshore grid may include different assets and equipment as they are operated at AC or DC, commissioned at different capacity levels, connected to a single or several offshore wind farms, or have different demarcation points between the offshore wind farm, the offshore grid and the onshore grid . Furthermore, in some cases the onshore point of connection may be close to shore or further inland. All of this has an impact on the overall cost levels of the offshore grid connection and should be taken into account when drawing comparisons between different countries. The regulatory estimation methods applied for offshore grid opex in different countries are however influenced by the general regulatory framework for offshore wind and the regulatory approaches to set allowed revenues of electricity transmission network operators.

Outside the Netherlands, offshore windfarms of larger size are currently in operation in British, German, Belgian, Danish and Chinese waters. Larger offshore wind farms are also under construction in France, Vietnam and Taiwan. Larger offshore wind farms at an advanced planning stage are also currently being developed in Norway, Sweden, the USA and South Korea. As the regulatory framework and electricity sector structure in the non-European countries in this list is quite different from the European countries, including among others a lack of unbundling requirements for network operators, we did not further analyse the regulatory framework of non-European countries in the following section.

Figure 3: European countries with explicit regulatory frameworks for offshore grid connections



Among the European countries with explicit regulatory frameworks for offshore grid connections the following regulatory approaches can generally be identified:

- Countries where the link between the offshore wind farm and the onshore transmission network is treated as a grid **connection** (similar to onshore grid connections) and not part of the main transmission grid: Sweden, Norway[9]
- Countries where the offshore grid connection is **tendered** together with the offshore wind tender and to be implemented by the offshore wind developer or a separate offshore transmission operator and owner (no regulatory cost review of the related opex): The United Kingdom, Denmark
- Countries where the offshore grid is part of the electricity transmission network and where opex are subject to an **ex-post regulatory cost review**: Belgium, Germany (new framework since 2019), Denmark (old framework until 2019)
- Countries where the offshore grid is part of the electricity transmission network and where opex are subject to an **ex-ante regulatory cost review**: Germany (old framework until 2019), France

The **United Kingdom** applies a tendering approach for both offshore wind farms and offshore grid connections. Under this regime, which applies for all offshore wind projects developed after 31 March 2012, power transmission from offshore wind projects to the onshore transmission network can be either designed and built by the offshore wind developer or a separate Offshore Transmission Owner (OFTO). The decision whether the OFTO buys or builds the offshore transmission system is taken by the developer of the offshore wind farm. All 20 offshore transmission assets commissioned since the implementation of the OFTO framework in 2009 have been designed and built by the offshore windfarm developer and implemented as direct point-to-point AC connections. Once the offshore grid asset has been built and commissioned, the asset ownership is transferred to an OFTO, who is responsible for operating and maintaining the transmission asset and which is selected through a competitive tendering process led by the British regulatory authority Ofgem. The selection of the OFTO is based on the annual revenue it requires to buy or build and operate the offshore transmission network. The bidder with the lowest required annual revenue requirements acquires the rights to buy the offshore transmission assets for a predetermined value, which is determined by Ofgem through an assessment of the efficient costs covering capital expenditure, development costs, interest during construction and transaction costs. The OFTO receives a constant annual revenue stream for 20 years based on its bid in the competitive tender, after which the OFTO license expires. The actual annual revenue of the OFTO is further subjected to a performance adjustment (upwards or downwards), which measures the availability of the transmission capacity against a regulatory target. The revenues (indexed for general inflation) are paid by the British TSO National Grid who transfers them to transmission network users via the transmission charges (paid by end-users and electricity generators). As such the efficiency and the level of the opex of the offshore grid connection in the United Kingdom are not subject to a regulatory review by the regulatory authority (neither ex-ante nor ex-post); instead the opex are a key parameter for the OFTO in determining its bid price in the tender.

In **Denmark** the Danish TSO Energinet had been responsible for the construction, ownership and operations of the offshore grid connection for offshore wind farms awarded in a site-specific offshore wind tender by the Danish Energy Agency. The costs of the offshore grid were assessed together with the onshore transmission network, for which a strict cost-plus regulation (ex-post regulation) had been applied in the past. Within this regulatory framework, the opex related to the offshore grid are not assessed separately. Alternatively, the offshore wind developer could take the initiative to establish an

[9] This was also the traditional regime for the initial first (smaller) offshore wind farms constructed closer to shore in other countries.

offshore wind power plant, in which case the owner of the offshore wind farm is responsible for the development and operation of the connection to the closest point with the onshore transmission network (open-door procedure). In this case the developer also has to recover the cost of the necessary facilities to transport electricity all the way to shore as well as the opex of the offshore connection. To date, no offshore projects have been completed under this regime, but nearshore windfarms are currently developed under this procedure. For upcoming offshore wind farms developed under the tendering procedure, the responsibility for constructing, owning and operating the offshore grid connection, including the offshore substation, moved to the developer winning the offshore concession. In this case, the Danish TSO Energinet is only responsible for the construction and operation of the onshore grid connection, whereas the developer needs to consider the costs for the onshore connection in its bid for the competitive tender. A regulatory assessment of offshore grid opex does not take place in Denmark.

In **Belgium** a so-called Modular Offshore Grid is currently under construction which will connect four offshore wind farms via a meshed grid including a single high-voltage offshore platform to the onshore transmission network. Elia, the Belgian electricity TSO is responsible for financing, developing, and operating the Modular Offshore Grid. Before the construction of the Modular Offshore Grid, the connection of the offshore wind park was undertaken by the respective offshore wind park developer. In decisions taken by the Belgian regulatory authority CREG,[10] controllable and non-controllable costs of the offshore grid are defined.[11] Controllable costs relate to non-recurring and preventive maintenance including the non-recurring maintenance of the electrical equipment, repainting, the replacement of the unloading dock, the replacement of the erosion protection of the platform structure and the replacement of auxiliary systems on the platform. The controllable costs of the offshore grid are based on the forecasted values of Elia and subject to an ex-post cost-sharing mechanism (also applying for the onshore grid), according to which 50% of the difference between the planned and the actual controllable opex – corrected for inflation – is to be shared with network users by accordingly adjusting the allowed revenues upwards (in case of cost undercutting) or downwards (when incurred costs exceed planned costs) in the following year. Repairs and reburial of damaged export cables, as well as repairs of the offshore platform (net of the insurance settlement) are treated as non-controllable costs passed through at their actual levels.[12]

The costs of the connection of offshore wind farms to the onshore transmission network in **Sweden** and **Norway** are to be recovered by the offshore wind developers. In 2018, the Swedish Energy Agency presented two proposals under which the offshore grid would either be part of the onshore transmission network (as in the Netherlands) or where the offshore wind developer would receive a subsidy which would (partially) cover the offshore connection costs. A decision has however not yet been adopted.

The connection of offshore wind farms in **Germany** is the responsibility of the electricity transmission network operators.[13] The offshore grid is part of the transmission network of the respective TSO. Allowed revenues of the TSOs are determined by a 5-year revenue-cap regulation, according to which maximum allowed revenues are set for the whole regulatory period based on regulatory approval of total

10 CREG Decision (B)1718 from 2018 on the general regulatory framework and CREG decision (Z)1109/10 on the specific approach for the regulatory period 2020-2023.

11 In addition, a depreciation period of 30 years (in line with the expected depreciation period for offshore wind parks) is applied and a risk premium for offshore grid assets of 1.4% throughout the entire regulatory lifetime is introduced.

12 Prior to the decision of CREG, Elia itself had estimated the operational costs to amount to 2.12% of the modular offshore grid's capex for the upcoming regulatory period and to an average 2.7% of modular offshore grid's capex over its regulatory lifetime. In its estimation, Elia disaggregated the estimated opex of the modular offshore grid over the regulatory lifetime for annual and bi-annual recurring costs, start-up costs, and estimated occurrences for cable repairs and other replacements.

13 That applies to three of the four German TSOs operating the transmission network next or close to the North Sea (TenneT Germany and Amprion) and the Baltic Sea (50Hertz).

expenditures (totex) in the base year of the regulatory period. Similar to the Netherlands, this includes an ex-post benchmarking of the total expenditures and an annual adjustment of allowed revenues according to a regulatory formula which takes into account the results of the benchmarking, a general productivity factor and inflation.

To consider the costs of expansion, investments incurred after the base year of the regulatory period in the allowed revenues, the instrument of "investment measure" is applied. On application by TSO and subject to regulatory approval by the German regulatory authority Bundesnetzagentur, the allowed revenue cap can be adjusted for the opex and imputed capital costs (including capital returns during construction) resulting from certain types of expansion investments conducted within the regulatory period. Capex of the investment measure are considered at the planned capex during the investment measure (reconciled ex-post in case of deviations of actual cost), whereas opex are considered via a lump-sum annual opex allowance. Cost considered under the investment measure are treated temporarily as non-controllable cost (pass-though) for the duration of the investment measure application. The cost will be included in the efficiency benchmarking of total expenditures in the next base year.

For onshore transmission expansion investments an opex allowance of 0.8% of the acquisition and production costs of the investment is applied.[14] To account for the specific incremental opex of offshore grid connections, a detailed analysis of the opex cost categories related to offshore grid assets was conducted by the Bundesnetzagentur, based on which a separate offshore opex allowance was determined. In the initial assessment in 2011, it was concluded that the opex allowance for offshore connections should amount to 3.4%, irrespective of technology or the TSO operating the grid.[15] This decision was based on a study that used planned opex data, manufacturer information and expert interviews.[16] Plausibility tests from data available to Bundesnetzagentur at that time confirmed the opex allowance, as the data had shown a bandwidth of opex percentage to capex from 1% to 6.6%.

Following the commissioning of a number of offshore wind parks and the corresponding connections by the TSOs, the allowance was reassessed by Bundesnetzagentur in 2017 with the support of an external consultant.[17] On the basis of substantiated data from incurred costs, the study concluded that the allowance of 3.4% does not represent efficient costs. In contrast, a bandwidth for an efficient opex allowance of 0.9% to 1.45% was suggested. The approach taken in the study can be summarised as a bottom-up analysis which included a review of which cost components should be included in the allowance, and to what extent the costs incurred may be considered efficient. The assessment could not identify individual opex estimations per asset group but derived a bandwidth for the total opex allowance by inclusion and exclusion of specific cost categories, which could not be fully assessed by the consultant advising the Bundesnetzagentur. These cost categories were a) insurances, b) reserves for decommissioning, c) start-up costs for direct current offshore grid connections, and costs for the clearance of unexploded ordnance. Detailed cost figures per opex category or TSO cannot be taken from

14 The opex allowance of 0.8% applies both for electricity and gas transmission networks. For gas, separate opex allowances have been decreed by the Bundesnetzagentur for compressors and pressure regulator stations, for which lump-sum opex allowances of 5.2% and 5.8% respectively are applied.

15 „BK4-11-0026 Festlegung von abweichenden Betriebskostenpauschalen für Offshore-Anlagen für Betreiber von Übertragungsnetzen bei der Genehmigung von Investitionsbudgets gemäß §23 ARegV"

16 „BK4-11-0028 Ermittlung abweichender Betriebskostenpauschalen für Investitionsbudgets gemäß §23 ARegV", study by TU Clausthal on behalf oft he Bundesnetzagentur, 5 October 2011.

17 „BK4-17-0002 Ermittlung einer Betriebskostenpauschale für Offshore-Anlagen", study by BET Büro für Energiewirtschaft und technische Planung GmbH on behalf oft he Bundesnetzagentur, November 2017.

the study supporting the decision of the Bundesnetzagentur as the values have been blacked out in the published version (if stated at all).

In 2019, the Network Tariff Ordinance was adjusted so that offshore grid connection costs are now charged to electricity end-users via a separate offshore levy (i.e. in addition to transmission network tariffs), which also covers costs of compensation payments (related to the non-availability of the offshore grid) and offshore grid planning costs. Following this change, offshore grid connection costs are no longer subject to the investment measure framework and a separate offshore grid opex allowance.[18] Instead opex (and capex) related to offshore grid connections are now considered at their actual values (ex-ante planned values are adjusted ex-post for the incurred costs). The respective ordinance enables the German regulatory authority BNetzA to set a company-specific threshold for the annual offshore grid opex in line with the expected efficient level of opex. Surpassing the respective threshold requires the TSO to justify the cost exceedance. As of now, however, no threshold has been set.[19]

In **France**, the connection of offshore wind parks with the onshore electricity transmission network is developed, financed, and operated by the French electricity TSO RTE since 2018.[20] There is no separate regulation for the costs of the offshore grid connections, but instead their costs are assessed together with the costs of the onshore transmission network of RTE for which a 4-year revenue-cap regulation applies.[21] Before 2018, the costs of the connection of offshore wind farms had to be recovered by the offshore wind developer.

To ensure efficiency of opex, the regulation requires an external ex-ante assessment of the projected cost components of the allowed revenue for the upcoming regulatory period. In this assessment an in-depth analysis of the projected expenses of RTE is conducted as well as – for the onshore part of the transmission network – the results of a European benchmarking with other network operators are considered. The assessment, which is conducted with the support of an external consultant, reviews all cost items that the TSO has proposed for inclusion in the regulatory asset base and allowed revenue calculation by applying a bottom-up approach.[22] The different cost items are disaggregated per cost category (i.e. asset management, engineering services and expertise, corporate functions) and sub-category (e.g. incident prevention plans, connection of offshore wind parks). The maintenance of the offshore wind park connection is furthermore differentiated by preventive and corrective maintenance and "others", which are then in themselves further differentiated by activity. The analysis includes an

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18 „BK4-17-002 Aufhebung der Festlegung von abweichenden Betriebskostenpauschalen für Offshore-Anlagen für Betreiber von Übertragungsnetzen bei der Genehmigung von Investitionsmaßnahmen gemäß § 23 ARegV", and

„BK4-19-074 Aufhebung der Festlegung von abweichenden Betriebskostenpauschalen für Offshore-Anlagen für Betreiber von Übertragungsnetzen bei der Genehmigung von Investitionsmaßnahmen gemäß § 23 ARegV"

19 In a separate procedure the Bundesnetzagentur has just recently also consulted on a separate opex allowance under the investment measure procedure for onshore opex for transmission assets under construction (i.e. for opex related to an investment measure prior to the commissioning of the investment), concluding in its draft decisions that opex for assets under construction are negligible and that no opex allowance should apply for this period.

„BK4-20-083 Festlegung zur Höhe der Betriebskostenpauschale gemäß §23 Abs. 1a S.2 ARegV für den Zeitraum bis zum Zeitpunkt einer Inbetriebnahme von Anlagengütern für Betreiber von Übertragungsnetzen", and

„Ermittlung der Betriebskostenpauschale Strom gemäß § 32 Abs. 1 Nr. 8c ARegV", study by Ebner Stolz Wirtschaftsprüfer Steuerberater Rechtsanwälte Partnerschaft mbB on behalf of the Bundesnetzagentur, October 2020.

20 „Délibération No.: 2018-227, Commission de Régulation de l'Energie"

21 The French regulatory authority CRE assesses and approves the provisional capex of the respective offshore investment and introduces an ex-post penalty and reward system for realized under- and overspending of capex relative to the provisional and approved capex. „Déliberation No.: 2019-015, Commission de Régulation de l'Energie"

In addition, principle conditions for offshore grid connections have been established by the regulatory authority "Annex 1 Délibération No.: 2018-227, Commission de Régulation de l'Energie"

22 "Audit du niveau des charges et produits d'exploitation de RTE", study by Schwartz and Co for CRE, November 2020

assessment of the difference between the projected costs in the recent and the upcoming regulatory period as well as of the adequacy of an inclusion of the respective cost item for a secure and efficient operation of the network. In addition, the external consultant may ask the TSO for justification of separate cost items.

Opex for the connection of offshore wind parks are assessed as part of the analysis of new cost items, given that no historic costs are available. In the assessment for the upcoming regulatory period, the external consultant found that no offshore grid opex attributable to “Engineering and Expertise” (*Ingénierie et Expertise*) should be included as they are uncertain and at risk of double counting. This category relates among others to (strategic) asset management and planning as well as external studies and stakeholder communication. After discussion with the TSO, the auditor approved some of the “Engineering and Expertise” costs associated with offshore connections, but dismissed costs related to the participation in research and development projects and consortia as not required for the efficient operation of the electricity network. Maintenance cost for offshore connections and subsea cables were projected on the basis of existing contracts and experiences. It is at the regulatory authority’s discretion to finally set the allowed revenue and the resulting transmission tariffs on the basis of the TSO proposal and the external assessment. Opex figures for individual opex categories and activities, as well as overall opex values per year and connection have not been made publicly available.

4.2 Available International Data

Given the smaller number of offshore wind farms of a larger size already in operation in different countries, only a limited sample of international opex data of offshore grid connections already in operation can be compiled, which can be used for comparative assessments. Furthermore, offshore wind farms in different countries could be built or planned at various distances to the shore, different water depths and ground conditions or the onshore point of connection may be in some cases close to shore or further inland. Moreover, connections to the onshore grid are operated at HVAC or HVDC, commissioned at different capacity levels, connect to a single or several offshore wind farms, have different demarcation points between the offshore wind farm, the offshore grid and the onshore grid and thereby include different assets and equipment. Furthermore, legal requirements regarding the operation and maintenance of offshore grid assets – related for example to health, safety and environmental regulation, which influence the offshore grid design and the maintenance policy – may differ across countries. In addition, in some countries only integrated cost data including both the offshore wind farm and the connection to the onshore transmission network is available. All of the aforementioned points have an impact on the overall cost levels of the offshore grid connection and should be taken into account when making comparisons of opex cost data between different countries.[23]

International comparisons for offshore grid opex can be done with regard to two main sources. In the United Kingdom, a number of larger offshore windfarms have already been operational for a number of years. Since the offshore grid connection in the UK is operated by separate Offshore Transmission Owners (see section 4.1), also separate cost data is available here. In addition, a note was published by Energinet in 2018, describing the grid connection costs of Anholt, Horns Rev 3 and Kriegers Flak.

[23] When expressed as opex in % of capex, it is also important to consider the capex level of the offshore grid connections based on which the opex percentage is calculated.

United Kingdom

OFTOs are obliged to provide their so-called "regulatory accounts" for every financial year (ending each March of every year). In these reports each OFTO (whose only task is the operation of offshore grid connection) provides among others a strategic report, a corporate governance statement and a regulatory financial statement. The latter also comprises of a section on operating costs, distinguishing between separate cost items falling in this category. Unfortunately, not all OFTOs follow the same structure of separation of the costs. The most common approach, e.g. applied by all OFTOs of the parent company "Blue Transmission", separates operating costs into three categories: "operations, maintenance and management" (representing "costs associated with the provision of operating, maintenance and management to the OFTO, which covers operation and maintenance costs, insurance premiums, management service fees and non-domestic rates related to the transmission network), "auditors' remuneration" and "other". For the financial year ending in March 2020, regulatory accounts with information on operating costs could be found for nine OFTOs[24] with an installed capacity between 184 and 630 MW. The operating costs were set into relation towards the capex as stated in the respective cost assessment documents of Ofgem.[25]

Figure 4: Operating costs as % of capex by MW installed capacity of nine OFTOs in 2020[26]

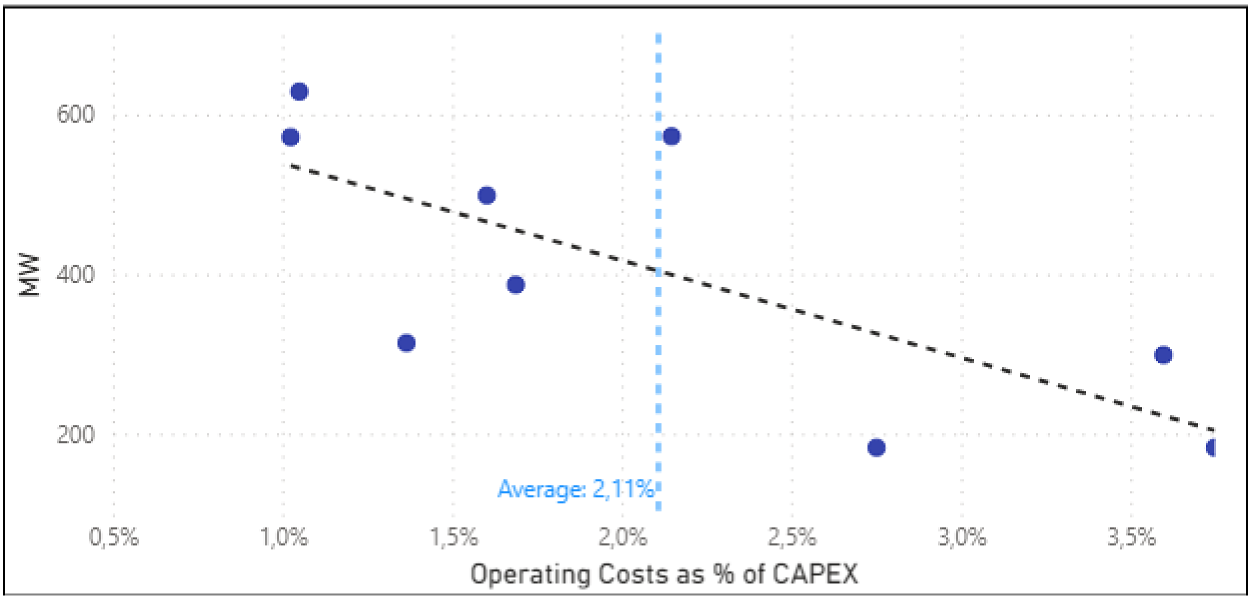


Figure 4 seems to indicate that operating costs in % of capex are lower for high levels of installed capacity of the offshore windfarm connection. Overall, the average is at 2.11% for the sample of all nine OFTOs. If only connections larger than 300 MW are taken into account (six OFTOs), this number is at 1.48%.

Considering only the "operations, maintenance and management" costs, disregarding cost items such as "other cost", "decommissioning costs", "auditor's remuneration" or credit loss provisions, which are likely to be rather individual components beyond the operation and maintenance costs, the share of operating costs as % of capex slightly is at 1.78% (based on seven OFTOs for which this information could be

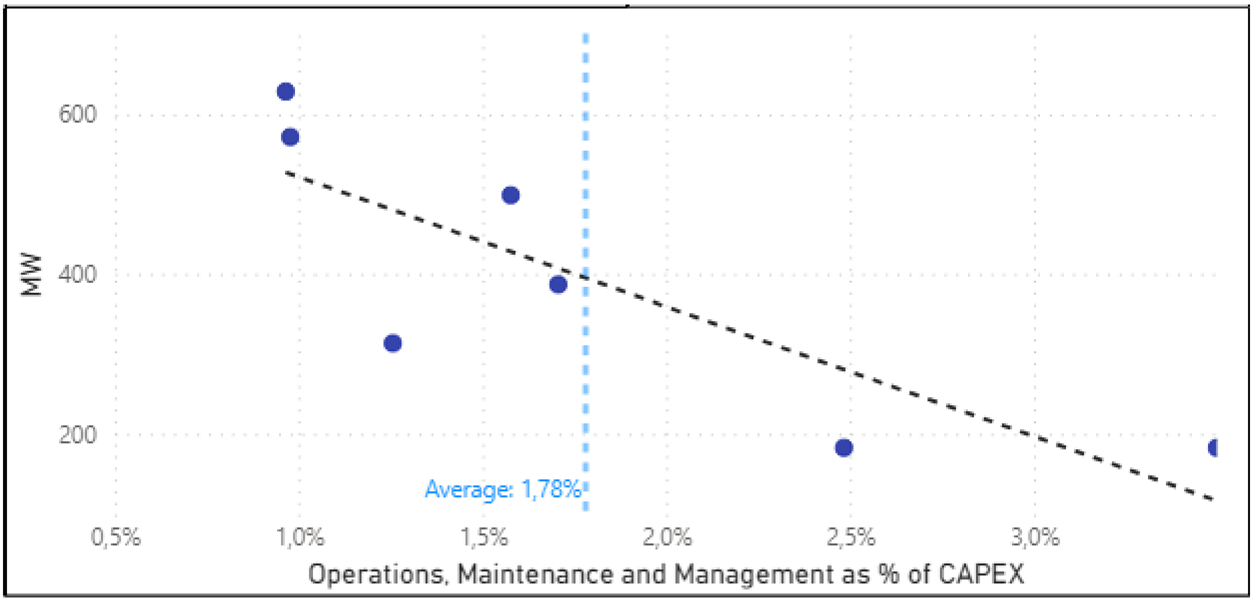
[24] Greater Gabbard, Gwynt y Mor, London Array, Race Bank, Sheringham Shoal, Thanet, Walney 1, Walney 2 and West of Duddon Sands.

[25] Capex category as part of the Final Transfer Value (FTV) of each transmission asset. In case the Final Transfer Value was not accessible, the Indicative Transfer Value (ITV) was used in the calculation (which was the case for one offshore connection).

[26] Source: DNV GL analysis

obtained).[27] When only connections larger than 300 MW are considered for this cost category, the average operating costs as % of capex are at 1.29%.

Figure 5: Operations, maintenance and management costs as % of capex by MW installed capacity of seven OFTOs in 2020[28]



Similar to the wider operating cost, the data also indicates for operations, maintenance and management cost that they vary with the size of the connection, leading to lower operations, maintenance and management cost as % of capex the larger the size of the connection is.

As mentioned at the beginning of this chapter, the results of the analysis of the OFTO figures need to be put into relation to the Dutch case. On the one hand, all of the OFTOs which were taken into account are connecting to a smaller amount of installed capacity and are closer to the shore than the windfarms of Hollandse Kust Zuid, Noord and West (700 MW connection, distance to the shore between 33 and 70 km) as depicted in Figure 6 and Figure 7.

27 Gwynt y Mor and Thanet did not further specify their operating costs in their Regulatory Accounts. Greater Gabbard did split the "Operations, Maintenance and Management" category into further subcategories ("Operations and Maintenance", Insurance, non-domestic rates and professional services). For the purpose of Figure 5 and the underlying calculation, these categories were summarised into one category to ensure comparability to the other OFTOs.

28 Source: DNV GL analysis

Figure 6: Installed capacity in MW of offshore grid connections of OFTOs and the average Hollandse Kust site[29]

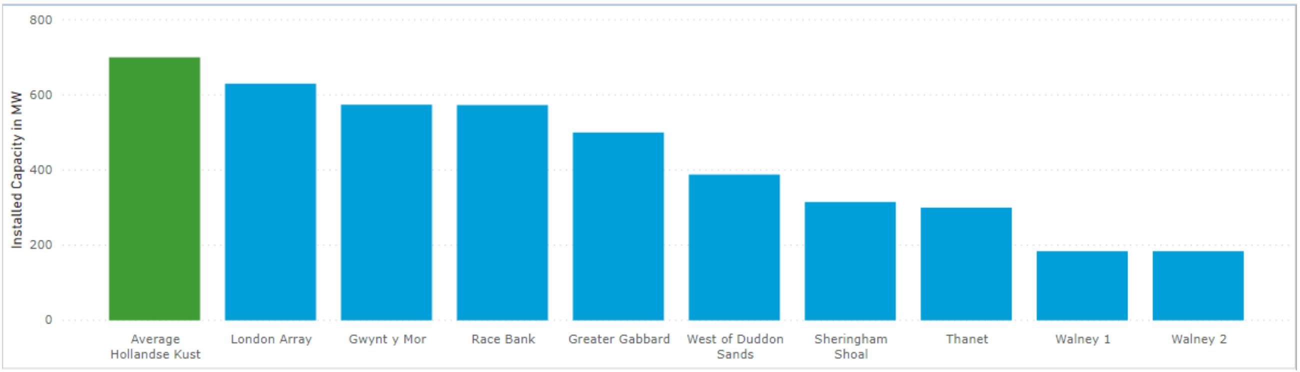
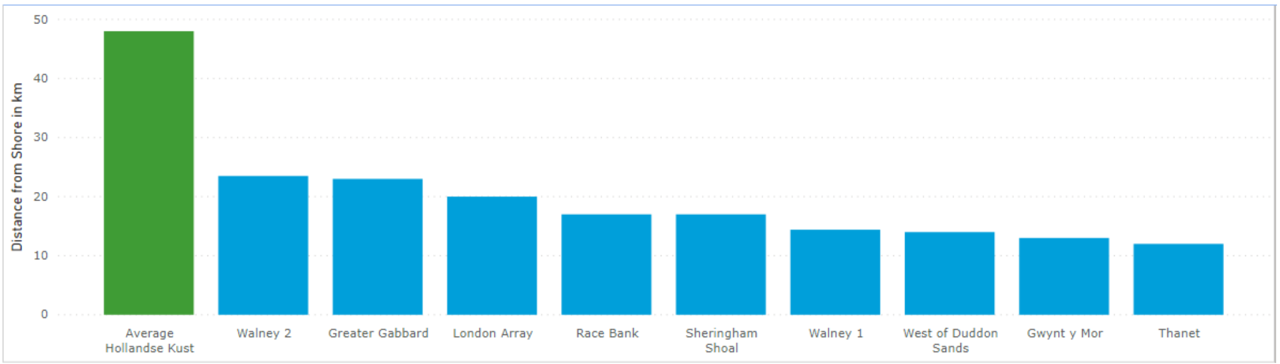


Figure 7: Distance to shore of offshore grid connections of OFTOs and the average Hollandse Kust site[30]



As the installed capacity and distance to the shore do have an impact on the capex and opex relation, and also the definition and valuation of individual cost items may differ to the Netherlands (which cannot be excluded from the published data), the values from the UK can serve only as an indication.

Denmark

In 2018, Energinet published a statement on the costs for grid connection of Anholt, Horns Rev 3 and Kriegers Flak following a request in the Danish Committee of Energy, Supply and Climate (Energi-Forsynings- og Klimaudvalget).[31] In this statement, Energinet describes the construction cost for the establishment of the grid connection (comprising e.g. of costs for the offshore platform, submarine cables or land cables) as well as the operating costs, containing costs for operation and maintenance, network losses and the compensation for lost production time. In the following overview in Figure 8 only the operation and maintenance costs are further considered as the costs for network losses are treated separately and the compensation for lost production is not included in the offshore grid opex allowance to be determined for the Netherlands.

The costs for operation and maintenance include for example the cost for IT and support. Unfortunately, additional cost items are not further described in more detail, which limits the comparability of these figures. Given the comparably low values of the opex as %-share of capex for the Anholt (0.56%), Horns

29 Source: DNV GL analysis

30 Source: DNV GL analysis

31 Redegørelse fra Energinet om omkostninger til nettilslutning af Anholt, Horns Rev 3 og Kriegers Flak

Rev 3 (0.48%) and Kriegers Flak (0.35%) offshore connections, we assume that insurance costs are not included in this cost position, which would then need to be added when comparing them to the Dutch case. Nevertheless, the same pattern as in Figure 4 and Figure 5 can be observed, since Kriegers Flak with 600 MW is larger than the other two sites at 400 MW installed capacity.

4.3 Evaluation of International Experience

The overview of the approaches applied by regulatory authorities towards offshore grid opex show that no common regulatory approach can yet be defined. While two countries (the United Kingdom and Denmark) are using a tendering approach to ensure cost efficiency of offshore grid opex, two are applying an ex-post regulatory review of opex (Belgium and Germany) or an ex-ante regulatory review of opex (France and the old framework in Germany). Most countries are however either treating the connection of offshore wind farms with the onshore transmission network as grid connections to be recovered from the offshore wind developers (not subject of a regulatory cost review as part of the determination of the allowed revenues of the transmission network operator, e.g. Sweden and Norway) and/or have not yet defined a dedicated regulatory framework for offshore grid connections. In the two countries where an ex-ante review of the offshore grid opex is or has been applied (France and Germany), this has been done so based on a bottom-up analysis, assessing offshore grid opex on an activity level or per main opex category primarily based on industry norms or expert judgements.

Top-down analyses require reliable cross-sectional data from external comparators. As TenneT is the only regulated provider of the offshore grid infrastructure in the Netherlands, the data should include companies from other countries. While top-down analysis would be more closely in line with the general regulatory approach applied for the onshore transmission network in the Netherlands, it will also require a sufficiently large sample of comparable actual data from offshore grid connections in other countries.

Based on our research on the regulatory arrangements in other European countries, as well as on data published by network operators and other stakeholders, actual opex data from comparable offshore grid structures is only publicly available to a limited extent. Given the limited number of offshore grid connections in operation across Europe to date, it appears to be difficult to collect such data from network operators. Furthermore, in order to compile a comparable data set, it is necessary to obtain a good understanding which cost items have been included in the respective opex figures. Our research shows that the available published data does not describe the cost structure in sufficient detail.

The currently available international data on offshore grid opex does neither allow to conduct a top-down benchmarking of offshore grid opex efficiency nor to simply transfer the observed opex shares in percentage of capex, for the purpose of determining an adequate opex allowance for the Netherlands. Also available data on realised costs of TenneT is limited to the realised costs for three months in 2019, and the granularity of data is low. For this reason, the application of top-down analysis based on comparative assessment does currently not appear feasible. As the application of a bottom-up approach appears to be the only option, we further evaluate and describe the properties of a bottom-up approach in the following chapters.

Nonetheless, the international data that is available, can provide useful insights in which range opex levels in relation to capex are generally to be expected. The data furthermore indicates that the installed capacity in MW and the distance to the shore are relevant cost drivers for opex levels, whereas a larger capacity tends to result in lower and longer distances to the shore tend to result in higher opex in % of capex.

Figure 8: Ranges of opex in % of capex for offshore grid connections based on available international data[32]

	United Kingdom	Denmark	Germany
Range of opex as %-share of capex	"Operations, Maintenance and Management"	"Operations and Maintenance"	Opex allowance for offshore connections
	0.96% - 3.50%	**0.35% - 0.56%**	**0.90% - 1.45%**
Comment	covering operation and maintenance costs, insurance premiums, management service fees and taxes	including IT and support costs, but not considering insurance	as suggested in study on behalf of Bundesnetzagentur (German Regulatory Authority) in 2017

5 EVALUATION OF BOTTOM-UP COST ASSESSMENT METHODS

When developing a bottom-up cost assessment approach and evaluating its properties, the following evaluation criteria should be considered, while taking into account the current regulatory framework in the Netherlands and the specific structure of TenneT and its grid. Specifically, we address incentives power, implication on return, transparency and simplicity, data availability and the administrative burden in the following section.

5.1 Efficiency Incentives and Return Implications

If the actual opex is passed through the allowed revenue onto network users, the company will earn the allowed rate of return, however it will most likely be less interested to engage and explore measures to improve efficiency. Therefore, regulators often apply incentives to encourage companies to improve efficiency and reduce cost. For example, if a company is able to outperform the regulatory allowance, it can be allowed to retain some of the earnings resulting from cost savings. Allowing the regulated company to retain / share the gains that arise from actions under their control for a specific period would give them an incentive to reduce the actual expenditure below the opex allowance, and in this way to disclose some of the efficiency improvement potential. If the achieved gains are taken away almost instantly by the regulator, or if the incentive targets are tightened immediately, after they have been met by the regulated company, the company has little incentive to achieve these targets.

On the other side, strong retention incentives could cause departure of actual from allowed cost and affect the return that the company effectively earns. Depending on the size of the impact, the latter might raise some distributional concerns.

Bottom-up methods appear attractive because they link the opex allowance with the estimated needs on individual activity level. At the same time, they account for efficiency consideration by using physical and

32 Source: DNV GL analysis

monetary norms in the estimation. Bottom-up methods may help to avoid large departures between the allowed and actual opex and stay closer to the allowed return level. This way efficient maintenance measures which ensure network reliability could possibly be accordingly be reflected in the cost assessment. On the other hand, the efficiency incentives of the regulated company strongly depend on the norms used and how closely they reflect the actual costs of the regulated company. The approach for the determination of the cost norms is therefore key for the efficiency under bottom-up approaches.

5.2 Transparency and Simplicity

It is important that the regulatory estimation method applied for cost assessment is comprehendible and transparent so that it is clearly understood and accessible by all stakeholders. Sometimes sophisticated and complex methods may be designed intending to further promote efficiencies. However, this may not necessarily encourage the regulated companies to respond better if the results and its implications are not clear and transparent to them. In particular, a micromanagement of the regulatory authority in relation to individual cost items should be avoided. Transparency also has the advantage of promoting accountability for their actions, by both the regulator and the regulated companies. It helps to avoid disputes and legal battles and improves the general acceptance of stakeholders.

To set long-term incentives for TenneT to react to the regulatory methodology when making investment decisions or adjusting their operational activities and their maintenance strategy, it is recommendable to avoid changing substantially the methodology from regulatory period to regulatory period. The selected estimation methodology should on the other hand be flexible to enable adjustments for unforeseen cost-relevant developments beyond the control of TenneT or for unintended unpredictable impacts on the wider regulatory framework.

In the specific project context, we believe that the bottom-up approach can be transparently presented in terms of concept, assumptions taken and data requirements, although the bottom-up assessment could possibly appear slightly more complex.

5.3 Data Availability

The implementation of regulatory cost assessment models requires data with adequate quality in terms of granularity, completeness and consistency. Without robust input data, the accuracy of the calculated results will be largely undermined.

Bottom-up analysis looks at the individual cost categories and activities. It sets cost norms for individual cost categories and activities by using engineering estimates. It can therefore also be applied in cases where comparative data is not available. Depending on the details of the chosen approach, bottom-up analysis may require though granular data of the regulated company reflecting the degree of opex disaggregation implied in the approach, which could possibly be data intensive.

5.4 Administrative Burden

The cost assessment method should be designed in such a way that its implementation limits the administrative burden both for TenneT and the ACM. This can be understood in terms of data collection, data submission and the complexity of the data analysis involved. This involves preparation beforehand and consideration of the specific characteristics of the method, which need to be taken into account in the selection process. Complex estimation methodologies could require high efforts in terms of data collection and calculation, which would not justify their implementation. Moreover, the overall level of possible efficiency savings, which can possibly be achieved by the application of a methodology, need to be considered, for example in the case when smaller opex cost items are assessed on a very detailed level.

As already explained, bottom-up analysis looks at the individual cost categories and activities. The administrative burden for the ACM (also considering the efforts of external consultants contracted by the ACM) depends on the level of granularity by which individual cost categories and activities are assessed, as well as which cost certain categories and activities are not to be considered in the offshore grid opex allowance but as part of the revenue cap for the regulatory period. The administrative burden for TenneT depends, in particular, on the granularity at which cost norms are compared with planned and actual data of TenneT. The approach could possibly be data intensive and can require substantial resources when the assessment is conducted on disaggregated data level.

Regarding the administrative burden, one should also consider the extent to which the value of the opex allowance will need to be reassessed before the start of each regulatory period. Considering learning effects, technological progress, economies of scale, further standardisation and possibly different offshore grid structures in the future, it is not unlikely that efficient opex levels in future regulatory periods will be different from the ones determined today. Moreover, more actual cost data will be available in the future, which can be considered for the determination of efficient offshore grid opex.

6 RECOMMENDED ESTIMATION METHOD

6.1 Opex Setting

In compliance with the approach used by the ACM for the regulation of electricity networks, the methodology applied for the determination of the opex allowance will be set ex-ante for the duration of the upcoming regulatory period. The opex allowance will then be calculated and determined by the ACM based on this methodology once a new offshore platform has been commissioned.

The methodology for the opex allowance has to reflect the efficient incremental operational cost incurred by TenneT in the upcoming regulatory period 2022-2026 that is attributable to the commissioning of new offshore network assets. Incremental means that the opex allowance should solely refer to the additional operating expenditure that TenneT will incur with the commissioning of new parts of the offshore grid between the 1st January 2021 and the 1st January 2027. Opex related to parts of the offshore grid that were already commissioned before the 1st January 2021 are already included in the allowed revenue set by the ACM for the entire regulatory period, i.e. they are not incremental by nature. Furthermore, indirect costs that already existed before the start of the regulatory period but are then reallocated from the onshore to the offshore grid due to different shares of the underlying allocation keys but not to a change in their level, are not eligible for inclusion in the separate opex allowance due to their non-incremental nature.

Overall, we favour the use of incentive regulation based on functional and non-intrusive methods to set the allowed cost, using comparative (top-down) analysis to set the opex allowance relative to the performance of other transmission network companies operating offshore. The top-down analysis is more closely in line with the general regulatory approach applied for the onshore transmission network. While the merits of this approach are also known by the ACM from the regulation of the onshore electricity networks, the credibility of the comparative assessment depends on the availability of reliable data. As explained in chapters 3 to 5, this approach is not suitable for the upcoming regulatory period due to insufficient historic offshore grid data from TenneT, as well as limited international opex data for offshore grids.

For this reason, we suggest applying a bottom-up analysis for the upcoming regulatory period, estimating the opex allowance by using an activity-based specification and standard costing approach. The elements of this approach are further described in section 6.1. In agreement with the ACM, the establishment of network loss allowance was separated from the opex allowance and is presented in section 6.2. The next chapter (7) sets out a quantitative estimation of the opex allowance for TenneT's new offshore network assets, describing the practical steps and assumptions taken to estimate an efficient value for the offshore grid opex allowance for the regulatory period 2022-2026.

As part of the project, TenneT was asked by the ACM on behalf of DNV GL to provide data and additional explanations on its expected opex related to the commissioning of new offshore platforms during the regulatory period 2022-2026, which included:

- A breakdown of the main opex categories for the major activities or items conducted by TenneT for each opex category
- The planned (expected) opex levels for each cost category and activity (including details on their calculation)
- An explanation regarding the extent to which an individual activity or item is incremental (i.e. varying with the number of offshore grid connections) and if it is attributable to the offshore grid
- A breakdown of the costs for individual activities in labour and non-labour costs
- Information on which activities are to be conducted by external 3rd parties

The information provided by TenneT has been used to cross-check the definition of individual activities as well as to obtain a better understanding on the cost allocation applied by TenneT. Furthermore, the information has been used to review the incremental nature of individual cost items and activities. Finally, the information provided by TenneT has been used to inform the analysis of specific cost items and particularly of overarching (supporting) costs and insurance costs.

6.1.1 General Method

Opex Specification and Eligibility

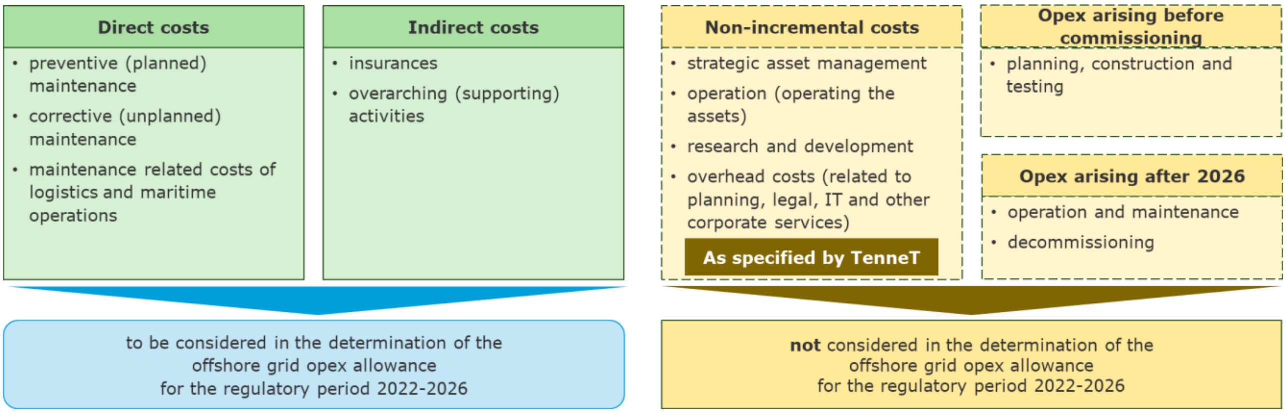
The opex allowance is established bottom-up using an activity-based specification for the main activities related to the onshore connection of offshore wind parks.[33] The direct costs are estimated by assessing the maintenance activities which comprises of preventive (planned) and corrective (unplanned) maintenance (including the maintenance related costs of logistics and maritime operations). The indirect costs, which are attributable to the offshore grid, but not directly attributable to a single platform, are estimated by analysing two activities which comprise insurance and overarching (supporting) activities. Asset management costs, operation (operating the assets), research and development costs and overhead costs (related to planning, legal, IT and other corporate services) have not been specified by TenneT as being incremental. As such, these cost categories are therefore not further considered in the

33 Activity-based costing approaches have been applied in the regulation of electricity (onshore) network operators in Austria, Ireland and Australia.

determination of the opex allowance, which covers the additional (incremental) opex related to offshore grids incurred by TenneT in the regulatory period 2022-2026 following the commissioning of the new offshore platforms.[34] The suggested specification provides a reasonable degree of disaggregation for the purposes of the cost assessment.

In addition, opex that arise after the end of the regulatory period 2022-2026 are to be considered in the opex allowance of the subsequent regulatory period(s). Accordingly, decommissioning and possibly differing maintenance costs for aging assets at the end of their lifetime are not part of the analysis. Opex related to the planning, construction and testing of individual offshore grid connections (which arise before the commissioning) are not considered here as these costs are typically capitalised and included in the asset value.[35]

Figure 9: Opex specification and eligibility



Principal Estimation Steps

Based on the activity-based specification explained above we suggest estimating first the annual individual cost allowances in absolute terms per category of main activity for each of the offshore platforms. According to the current offshore development framework, five of the Hollandse Kust offshore platforms are expected to be commissioned during the regulatory period 2022-2026 and should therefore be considered with their expected commissioning dates when estimating the opex allowance. A detailed explanation of the approach proposed to assess the cost allowances for individual activities and items is provided in the following sections.

The annual individual cost allowances of the individual platforms in a specific year are then added together in order to obtain an absolute total annual opex allowance for that year of the regulatory period. In order to establish the absolute total opex allowance for the regulatory period the total annual values are to be aggregated. Based on the absolute total opex allowance a single average figure for the percentage opex allowance for the regulatory period could be derived by dividing it by the aggregated planned (weighted) capex of the offshore platforms .

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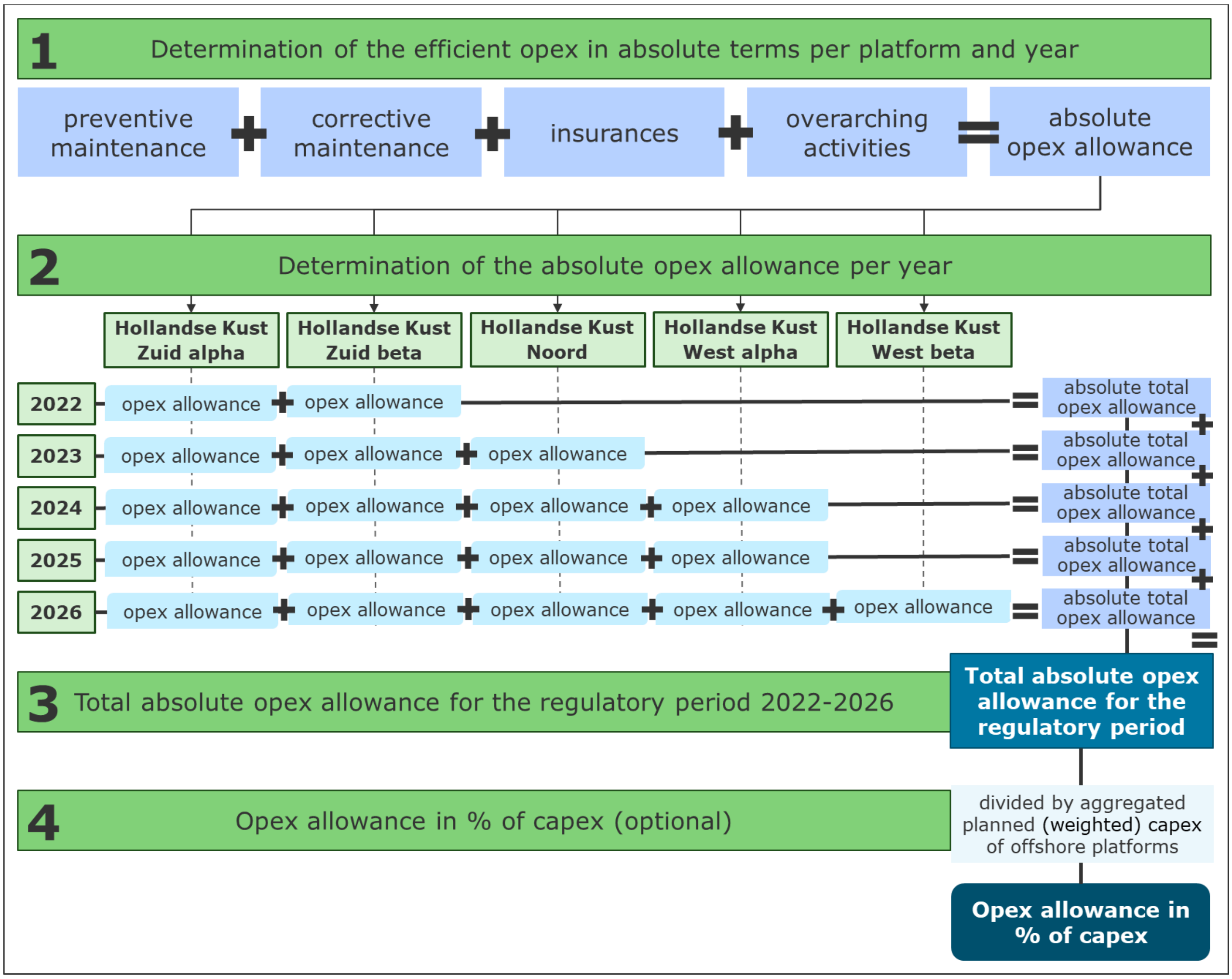
34 Costs of production outages due to non-availability of the offshore grid are also a relevant opex item for offshore grid connections. In the Netherlands these costs are however generally a cost pass-through item and therefore not included in the opex allowance.
TenneT needs to compensate offshore wind farms in two situations: 1) if the relevant part of the offshore grid is not commissioned on the date fixed in the Offshore Development Plan (ontwikkelkader) and the offshore wind farm is therefore not able to transport its electricity and 2) if the offshore wind farm is not able to transport its electricity due to maintenance works that exceed 5 days per calendar year. The costs of delayed commissioning or of production outages dues to maintenance work from day 6 need to be compensated by TenneT but are generally passed through to the tariffs. Only in case of gross negligence the costs of interruptions will not be passed through. In case of gross negligence only the costs of outages that exceed 10 million will be passed through.

35 This was also the outcome of a recent study conducted on behalf of the German regulatory authority Bundesnetzagentur, according to which opex for assets under construction are negligible (see Footnote 19).

The principle steps for the estimation of the opex allowance according to the above approach are summarised in the following figure.

Figure 10: Principle steps for the estimation of the opex allowance for the regulatory period 2022-2026



Indexation

In line with the approach applied for the onshore transmission network, we recommend indexing the annual opex allowance with changes in the price inflation (consumer price index (CPI)) in the Netherlands. While in principle other price indices could be applied, more closely reflecting the input price inflation relevant for the transmission network of TenneT, such indicators would be more difficult to compile, since published price indices and weights may not necessarily better represent the development of input prices relevant for the offshore grid opex.

Furthermore, the ACM may consider additionally adjusting the allowance with the expected productivity improvement by applying the general productivity factor (frontier shift), for the offshore parts. It can be argued that the potential productivity improvement in the upcoming regulatory period is limited as the maintenance concept will be applied to the existing asset base, which will not largely change in the regulatory period. On the other hand, it is realistic to expect a positive cost impact resulting from standardisation, economies of scale and learning effects in the process of the subsequent commissioning of the wind platforms. This would also ensure consistency with the determination of the allowed revenues of the onshore and offshore network of TenneT, for which the productivity factor is already applied.

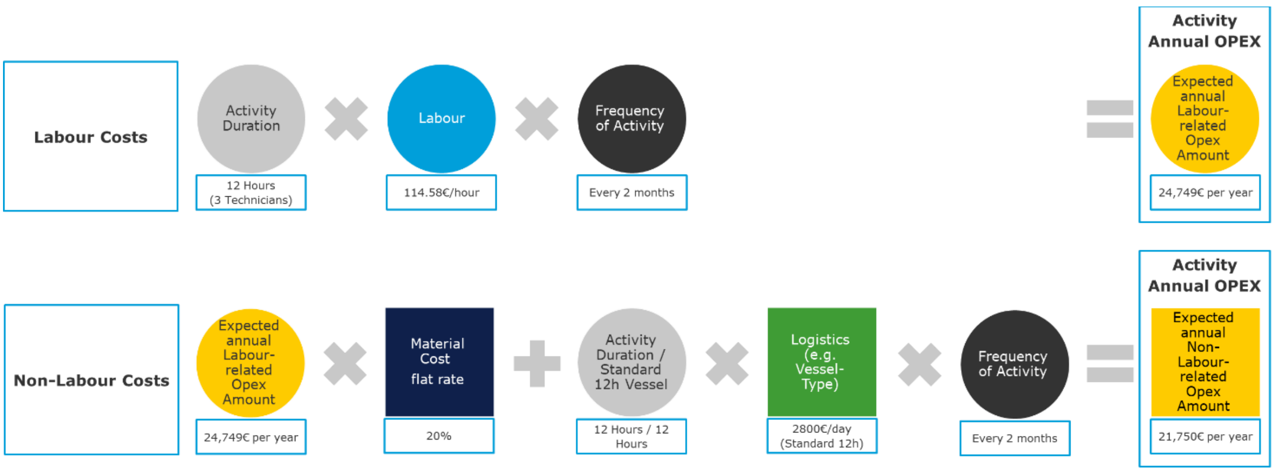
6.1.2 Approach by Main Opex Activities

To estimate the efficient opex of the main opex activities, we suggest applying a sufficiently detailed break-down of individual activities to enable a reasonable assessment for regulatory purposes. The main opex activities relevant for the determination of an incremental offshore grid opex allowance are (as specified in section 6.1.1):

- Preventive maintenance
- Corrective maintenance
- Maintenance related logistics and maritime operations
- Insurance
- Additional overarching activities

The breakdown for individual maintenance activities should, include a breakdown of the opex per activity in labour unit costs, materials costs and other non-labour costs (e.g. transport and logistics costs) and a breakdown of maintenance costs by main asset group. To reflect the different requirements and cost levels, preventive maintenance can be further differentiated in intrusive and non-intrusive maintenance. Intrusive maintenance requires the equipment to be disconnected while the maintenance is conducted, whereas non-intrusive maintenance can be conducted while the offshore grid is in operation respectively. In addition, the costs of insurance and, where and if relevant, additional (i.e. incremental) overarching costs are to be added. The opex allowance is then determined by the sum of the estimated efficient opex for each individual opex activity. An example of the application of this general approach for an individual preventive maintenance activity is shown in the following figure. Further details on the suggested approach for the different maintenance activities are provided in the following sections.

Figure 11: Proposed break-down of opex by main activity (Example of HKZ Alpha in 2022 for preventive maintenance of Fire Protection System)



When evaluating the efficiency of the maintenance and operational management costs, it is also important to consider the possible impact of outsourcing activities to external third parties. Selecting an internal solution may require training personnel which may incur higher costs at the start, but possible savings at a later stage. Whereas in the case of outsourcing, contracting personnel and services from 3rd parties, such training costs may not arise, but overall opex levels over the complete duration could possibly (but not necessarily) be associated with higher costs compared to in-house solutions. We generally recommend abstaining from regulatory micromanagement by explicitly or implicitly prescribing a preference of internal provision or outsourcing specific activities, and determining the opex allowance independent of an internal or external provision of individual activities.

Furthermore, when individual activities are entirely or largely outsourced to external third parties, it appears questionable, if substantial internal costs would still be claimed for these activities by TenneT beyond the procurement and coordination of these activities. In this case, differences between the bottom-up determination of the efficient opex allowance based on a standard costing approach and the cost figures submitted by TenneT may be expected.

6.1.2.1 Preventive Maintenance

To estimate the preventive maintenance costs for individual asset categories, the expected efficient frequency of individual maintenance activities of assets and equipment in this category should be specified first. Where an individual preventive maintenance activity is to be conducted in a larger frequency than annually, we consider the maintenance costs in the year in which they are expected to occur. If this year is within the upcoming regulatory period (2022-2026), the costs of the individual maintenance activity are to be considered in the opex allowance. If the maintenance activity is expected to occur after the duration of the upcoming regulatory period, the maintenance costs will not be included in the opex allowance for the upcoming regulatory period, but in the opex allowance of a subsequent regulatory period. This will ensure that the opex allowance only considers opex which are expected to occur during the regulatory period. If the commissioning of an offshore platform is significantly delayed (compared to the current timeline), an ex-post review may be considered by the ACM in order to identify the extent to which the actually incurred opex of TenneT deviated from the ex-ante determined opex allowance (upwards or downwards) because of a different date of commissioning. If the effect of such a delay is of a relevant size, allowed revenues of future periods may be adjusted accordingly.

The costs of preventive maintenance are driven by the number of hours used to deliver the maintenance activities (labour time norms), reference labour unit costs and the additional non-labour costs (cost of materials and logistics e.g. vessel costs).

The labour time norms are a function of the frequency and duration of the required individual maintenance activities by asset group (including the number of required employees) as well as the necessary travel time.

The reference labour unit costs (EUR/hour) can be estimated based on the type of the required employees for this specific activity, the average salaries of the relevant job categories (including all employer contributions) and a utilisation factor for the specific type of employee. This should account for the fact that a technician or engineer will not or is not able to spend 100% of his/her working time offshore for maintenance purposes. The reference labour unit cost are established by using statistical data on monthly or annual remuneration per relevant job category in related industry sectors.

The time norms for logistics / marine operations are based on the number of trips, duration per trip (travel time and time spent offshore) and the type of ship required for the execution of the maintenance activity. The cost of materials is expressed as a percentage of labour costs for individual maintenance activities.

The costs of preventive maintenance are to be determined for each individual maintenance activity. The total costs for preventive maintenance are then derived by adding together the estimated requirements of the labour and non-labour opex components for each individual activity. The figure below provides an overview of the main maintenance and cost categories.

Figure 12: Activity related cost categories for preventive maintenance

Asset Categories	Maintenance Categories	Activity-related Cost-Categories: Labour Cost	Activity-related Cost-Categories: Material Cost	Activity-related Cost-Categories: Transport Cost
Offshore platform structure	High Voltage Installations; High Voltage Secondary Systems; Jacket; Topside; General	By activity and maintenance type (intrusive, non-intrusive and corrective)	By Material Cost Flat Rate	Mostly Standard-Vessel Cost
Export cables	Export Cables	By activity and maintenance type (non-intrusive and corrective)	By Material Cost Flat Rate	Survey-Vessel Cost
Onshore Station	High Voltage Installations; High Voltage Secondary Systems	By activity and maintenance type (intrusive and non-intrusive)	By Material Cost Flat Rate	None

Maintenance by manufacturer is sometimes provided as a third-party service to network operators (opex) and sometimes included in the purchase price for the asset (capex).[36] In case of doubt, the ACM can request information on what is covered by the warranties and to what degree maintenance by manufacturers is included in opex or capex.

Given the limitations to the publicly available international data from offshore grids in operation, we suggest determining the labour time norms based on best engineering practices. The latter reflects the experience with offshore grids, as well as experience with the maintenance of similar assets and equipment of onshore transmission networks, while taking specific Dutch legal requirements into account, such as health, safety and environmental requirements as defined in the water law and the related water permit. In chapter 7 we present a quantitative estimation. The estimation takes experience from previous projects of DNV GL into account , while accounting for the main characteristics in offshore grid design (e.g. AC/DC, platform type, soil conditions, water depth, capacity), the shore distances of the five offshore platforms to be commissioned in the next regulatory period and the relevant Dutch regulations.

6.1.2.2 Corrective Maintenance

When looking at corrective maintenance, in principle the same approach taken for preventive maintenance is applied as regards labour and non-labour cost norms (labour time norms, reference labour unit costs, materials and vessel costs). The labour time norms for corrective maintenance should be estimated based on the time needed to execute potential repairs, whereas the potential occurrence of the latter reflects the statistical probability of equipment failures. While for preventive maintenance a specific maintenance schedule based on best engineering practice could be applied for the estimation, only the probability for a specific corrective maintenance activity can be estimated. As such, a specific corrective maintenance activity may need to be conducted earlier or later than the statistical probability. Due to this uncertainty we prefer considering corrective maintenance activities in the opex allowance, which are statistically expected to occur within the duration of the regulatory period. However, we suggest not including rare corrective maintenance activities, for which the statistical probability indicates an occurrence beyond the regulatory period. The costs of individual corrective maintenance activities for cable repairs should be considered in the annual opex allowance on a pro-rata basis.

36 It is also important to avoid double counting, when the maintenance of specific assets and equipment is to a large extent covered by warranties of the manufacturers in the first years of operation. As mentioned before, we recommend abstaining from regulatory micromanagement by explicitly or implicitly basing the calculation of the allowance on assumptions of the coverage of the warranties for individual assets and equipment.

6.1.2.3 Insurance

For insurance costs, a bottom-up determination of an efficient cost level for insurance fees is more difficult to provide due to the lack of standardised publicly available values. On the one hand, it can be assumed that insurance costs further decrease over time, considering that more experience is gained by grid operators in the design, construction, maintenance and operation of offshore grids. In addition, insurance companies will have gained more experience in calculating their insurance premiums for offshore wind grid connections. Furthermore, with increasing numbers of offshore grid connections being implemented, insurance companies will be able to better balance their risks across a larger number of insured offshore grid segments. As the insurance fees could also be subject to specific features of the individual offshore grid connection, we recommend including insurance fees with their planned values in the ex-ante opex allowance.

When insurances for given activities are procured at market rates, insurance costs can generally be considered reasonable. In practical terms, the ACM may request TenneT to provide relevant evidence, for example by presenting at least three alternative insurance offers (possibly collected in an open competitive tender) and the reasoning behind the selection of the preferred offer. Such an information request would be a part of optional ex-post review initiated by the ACM, if there is reason to assume that the planned insurance costs submitted by TenneT and included in the opex allowance may not reflect the market level. When evaluating insurance costs, the scope of the insurances also needs to be taken into account. If the scope of the insurance is inadequate, the insurance costs may be considered as inefficient even when they are procured at market rate. If TenneT is following an insurance policy that is more open to risks, this could potentially result in higher corrective maintenance costs and a higher level of capital expenditures related to replacements of asset and equipment. Alternative scenarios with regard to different levels for insurance costs are estimated in chapter 7.

6.1.2.4 Additional Overarching Costs

To determine the efficient cost levels for additional overarching costs, it is important that only overarching costs which arise because of the commissioning of additional offshore grid segments are included in the opex allowance. Overarching costs that relate only to a different allocation of costs between the onshore and offshore grid or which remain constant regardless of the number of commissioned offshore grid connections, are (as explained at the beginning of this chapter) not to be included in the opex allowance as they are not incremental and would already be considered as part of the allowed revenues set for the existing assets.

To enable the ACM to review the relevance of costs in this category, it will be important for TenneT to provide the ACM with a detailed break-down of the costs in this category and to provide a detailed explanation of the nature of each individual cost item as well as to what extent the costs for the operation of the offshore grid assets are of an incremental nature.

6.2 Network Losses

In addition to opex, the allowed revenue will also include the cost of the allowed network losses for the offshore grid. Network losses refer to electricity that is lost in electricity networks. These are energy units that are transformed into heat and noise during the transportation process and therefore physically lost. The cost of network losses is the cost of purchasing energy to cover network losses.

Similar to the approach used for the onshore network, the cost of network losses for the offshore grid infrastructure is to be determined separately from the opex allowance.

We suggest setting the cost of the allowed network losses for each year of the regulatory period by multiplying the allowed loss quantity by a reference price. The latter represents the annual monetary value attached to the allowed loss quantity. In order to ensure the recovery of efficient cost, the price term should be set with reference to wholesale market prices. This approach also has the advantage of being objective and transparent. Accordingly, the ACM can establish the reference price as a weighted average of a representative baseload and peak load price (for futures). The representative baseload and peak load price can be calculated as the historic daily average price of a period of 12 months before the delivery year.

The allowed loss quantity can be directly set as an absolute quantity (MWh) or calculated as the product of a loss percentage allowance (%) and the planned transported electricity. Furthermore, the allowed loss quantity may be averaged during the years of the regulatory period or set individually for the respective year reflecting the expected network losses in that year.

At a given configuration of the assets, the physical loss quantities largely depend on the transmitted power flow and the cable length. Network losses change in the same direction as power flows increase and decrease (proportionally to the square of the current). Additionally, network losses increase with the length of the network line as they vary in proportion to the conductor resistance. The resistance of a conductor increases as its length increases. For cables of longer distance reactive power also becomes more relevant which has a negatively effect on the level of losses. Besides such variable losses that occur when wind power is transmitted, losses also occur during periods of zero wind energy generation because the system is electrically energised.

In the absence of external benchmarks, the allowed loss quantities can be set with reference to the actual network losses from previous years and the forecasted network losses. Currently the ACM does not have sufficient information available on the actual network losses for offshore grids from previous periods. Therefore, we suggest setting the allowed loss quantities for the upcoming regulatory period based on loss estimation for the regulatory period provided by TenneT. The estimation should include the results of the load flow simulations and the underlying data/ assumptions including the ones for the planned wind production (wind power output duration curve).

7 QUANTITATIVE ESTIMATION ACCORDING TO RECOMMENDED METHOD

In this section, the bottom-up estimation according to the methodology presented in the previous chapter is applied for the quantitative estimation of an efficient offshore grid opex allowance for the regulatory period 2022-2026. This includes an explanation of the quantification of each item and of the underlying assumptions, as well as different regulatory approaches for the specification of the opex allowance (e.g. in absolute terms or in percent of capex).

In section 7.1.1. general assumptions, such as labour unit costs rates and assumptions for inflation, are discussed. Following this, the assumptions and approaches for the determination of the maintenance costs by asset type and activity are described (section 7.1.2). Section 7.1.3 covers the estimation of insurance, additional operational and overarching costs. Ranges and scenarios of adequate and efficient values for an offshore grid opex allowance for the regulatory period 2022-2026 are presented in section 7.1.4.

7.1.1 General Assumptions

In the following section we describe the assumptions taken with regard maintenance activities.

Labour unit costs

The maintenance of offshore grid connections includes different technical activities performed by technicians and/or engineers with various qualifications. Therefore, the estimation for the labour unit cost (per hour) should take into account differences in job levels to the extent that they are relevant to the labour costs.

To account for this, the labour unit costs are determined based on the statistics of the Dutch Centraal Bureau voor de Statistiek (CBS), using 2018 data for various sectors (SIC 2008 classification), covering activities related to the offshore grid connection. The wage costs presented in the statistics from CBS, cover the cost for wages, social contributions paid by employers, taxes and possible wage cost subsidies. To reflect the different activities related to the offshore grid maintenance, an equal weighting of four sectors was applied, as presented in Table 1.

Table 1: Wage unit costs in Euro per hour for different sectors according to CBS

SIC Code	Branch/Sector	Weighting	Wage costs
26	Manufacture of electronic products	25%	47.1
27	Manufacture of electric equipment	25%	41.1
35	Energy supply	25%	46.6
42	Civil engineering	25%	38.3
	Average across sectors	**100%**	**43.28**

The average labour unit cost is adjusted to account for utilisation with a factor of 2.5, implying the utilisation of a technician of around 40%, accounting for vacation days, sick leave, training and administrative processes, potential possible danger allowance and overtime compensation (long shift compensation). As this factor is largely dependent on the organisational policy and the process management of the company, an external estimation is inherently difficult. We consider the suggested factor of 2.5 a reasonable proxy. Accordingly, the average labour unit cost is estimated at EUR 108.2 per hour for maintenance activities performed by TenneT staff. This value also reflects experiences from other grid connection projects DNV GL was involved in. In addition, all activities are estimated to be conducted with at least three technicians, even if some activities could from a technical standpoint also be performed with less staff on site, serving Dutch legal and HSE requirements.

For services provided by external third parties, in its answers to DNV GL TenneT has stated that the total envisaged labour costs of EUR 447,000 per platform per year arise from approximately [redacted] hours, which would imply an hourly rate of EUR [redacted] for services provided by external third parties.

Both figures have been weighted according to the hours forecasted by TenneT resulting in weighted average labour unit cost of around EUR [redacted] per hour. This value was applied for all maintenance-based activities in the estimation for which the required efforts in hours have been estimated by DNV GL according to the bottom-up activity-based approach. It was also applied for parts of the operation and overarching costs for which a breakdown of labour and non-labour costs was provided by TenneT and for which values provided by TenneT have been applied in the base estimate.

The latter includes “operational management”, “support functions”, “safety, health and environment” and “controlling and warranty management”. For other overarching costs performed by external third parties, covering IT-costs and telecommunication as well as 24/7 support lines and systems (related to the SCADA system), no break-down in labour and non-labour costs has been provided by TenneT.

Transport and logistic costs

Transport and logistic costs are mostly driven by the costs for the vessel which is needed for the specific activity. A standard vessel for the transport of personnel is sufficient for most activities. For predominantly cable surveys though, a larger survey vessel with a different cost structure is needed. In our calculations we assume that a standard vessel will cost around 2,800 EUR per 12-hour shift, while a survey vessel will cost around EUR 9,000 per 24-hour shift, including the vessel spread (i.e. the basic crew and equipment). Additional mobilisation costs of around EUR 90,000 per completed maintenance task performed with the help of a survey vessel can occur, reflecting in particular costs related to the mobilisation of the vessel. These costs are associated with the cost of hiring the vessel and bringing it to the site ready to work, special equipment inside it (such as a remotely operated vehicle, crane and tools) and the special technicians and crew of the ship itself, as well as the necessary demobilisation.

The transport and logistic costs are estimated by DNV GL based on experience from the work on previous offshore wind projects in Western Europe. We assume that the costs incurred for vessels are largely similar across Western Europe and therefore also in the Netherlands. In the calculation of the opex allowance, transportation costs are assigned to each maintenance activity on stand-alone basis, without explicit considerations of potential synergies resulting from the combined delivery of maintenance activities.

Costs for the storage of new cables or other consumables were not taken into account as this was not reported as being incremental by TenneT.

Material and consumable

Based on our experience, material and consumable costs only account for a smaller share as they generally primarily concern lubrication, oil filters or change of contacts. In relative terms, higher costs are to be expected for the non-intrusive maintenance of cables. In its reply to DNV GL, TenneT reported that the contracts with external third-party service providers include material costs of EUR 94,000. This amounts to around one fifth of the contracted labour costs. In our calculation, a percentage mark-up of 20% on the labour costs for individual maintenance activities is applied.

7.1.2 Maintenance Activities by Asset Type

The major drivers for the maintenance costs of transmission assets and equipment are the associated frequencies and efforts of preventive and corrective maintenance works. In general, the availability of industry-specific data in this field is rather limited. In addition, the specific design characteristics of the electricity infrastructure associated with the planned offshore platforms is currently still undefined or not available to us. For these reasons the maintenance costs are estimated in a bottom-up fashion by assuming generic design features with regard to individual electrical equipment of the offshore grid connection.

Specifically, the estimation applies modelling assumptions based on DNV GL’s experience, considering actual figures for similar size HVAC transmission assets and figures for planned maintenance costs of soon to be operational offshore grid projects, and public domain sources. Consequently, the results remain inherently generic and should be regarded as indicative. Furthermore, it is important to note that the actual preventive and corrective maintenance activities should generally be carried out in line with the Original Equipment Manufacturer guidelines. The latter may be different to the assumptions used to estimate the maintenance needed for the individual components.

The parameters used to provide a high-level estimation of the maintenance costs for the planned five *Hollandse Kust* platforms, are listed in the table below.

Table 2: Overview of to be commissioned platforms of Hollandse Kust

Platform	*MW*	*AC / DC*	*Export cable system*	*Total capex in €*	*To be commissioned by*
Hollandse Kust Zuid alpha	700	AC	2 x 36km	371,968,492	31.12.2021
Hollandse Kust Zuid beta	700	AC	2 x 36km	325,606,645	31.03.2022
Hollandse Kust Noord	700	AC	2 x 33km	425,727,738	31.03.2023
Hollandse Kust West alpha	700	AC	2 x 70km	543,228,395	31.03.2024
Hollandse Kust West beta	700	AC	2 x 65km	583,991,648	31.03.2026

The maintenance activities for the offshore grid connection include the provision of maintenance of the equipment in the offshore platform, export cable and land station. For the purpose of the estimation of operational expenditure for these projects, the maintenance activities have been split into the following tasks:

- Non-Intrusive preventive maintenance (no outage or no impact on power transmission is required) scheduled for all parts of the offshore grid connection
- Intrusive preventive maintenance (outage or impact on power transmission is required) scheduled for most parts of the offshore grid connection
- Corrective maintenance of the cables and cooling systems offshore[37]

7.1.2.1 Platform

The platform can be divided into five asset categories (high voltage installation, jacket, topside, high voltage secondary systems and others) and three different maintenance types (non-intrusive, intrusive and corrective maintenance). Based on DNV GL's technical expertise and experience from other offshore wind grid connection projects, we use 26 main non-intrusive maintenance activities, five main intrusive maintenance activities and one corrective maintenance activity relevant for the duration of the upcoming regulatory period 2022-2026 in the estimation, considering, as explained in section 6.1.2, up to the first five years after commissioning.

Table 3: List of maintenance activities on the platform

220kV/66kV Power transformers (non-intrusive inspection tasks)
220kV/66kV Power transformers (intrusive maintenance)
220kV/66kV Power transformers (intrusive maintenance of cooling system)
220kV Shunt reactors (non-intrusive inspection tasks)

[37] Corrective maintenance activities for other types of assets and equipment are expected not to occur during the first five years of operation, which are also partially covered by the warranties of the manufacturers.

220kV Shunt reactors (intrusive maintenance)
220kV Shunt reactors (intrusive maintenance of cooling system)
Earthing transformers
220 kV GIS
66 kV GIS
66 kV GIS (intrusive)
66 kV cables and sealing ends
220 kV cables and sealing ends
Control and protection 220 kV (computer upgrades)
Control and protection 220 kV (battery upgrades)
Communication network
Structural components
Electrical components and control system
Fire protection system
Safety and emergency response system
Topside paint repairs
Foundation paint repairs
Primary steel (scour inspection)
Primary steel (cathodic protection)
Primary steel (anode visual inspection)
Primary steel (splash zone visual and NDT inspection)
Primary steel (removal of marine growth and guano)
Secondary steel
General housekeeping (other)
Lighting system
Air conditioning system
Water and oil containment
Corrective maintenance of cooling systems (reactor/transformer)

Most of the hours regarding preventive non-intrusive maintenance are spent on the maintenance of the 220kV switchgear, the fire protection system, general housekeeping, the safety and emergency response system, water and oil containment and inspection of the transformers. DNV GL has identified additional mobilisation costs for the tasks of scour inspection and anode visual inspection (see section 7.1.1). These costs are included in the transportation/vessel cost.

Intrusive maintenance tasks only occur after four to five years after commission, concerning mostly the high voltage installation (transformers and reactors). There is no major corrective maintenance expected within the first five years of commission, with the exception of corrective maintenance for the cooling system for both reactors and transformers (expected to occur once in five years on average for both).

7.1.2.2 Export Cable

Two maintenance activities were identified regarding the export cable. The first is the non-intrusive maintenance of the cable (including joints and sealing ends) and the second is the corrective maintenance (cable repair) to eradicate cable failures.

Regarding the non-intrusive maintenance, the Ministry for infrastructure and water management (Ministerie van Infrastructuur en Waterstaat) stated in its permit that "the permit holder will monitor the first two years once every six months the location of the cables in the Maasgeul. After this, an annual monitoring research into the depth of the cables is executed."[38] This means that in the first two years after commission the frequency for non-intrusive maintenance for connections in this region is higher than in the following years. The expected speed of the non-intrusive maintenance activity is at 5km cable per day (based on DNV GL experience), resulting in 4.8 labour hours per km. As Hollandse Kust's stations of do have different cable lengths to the shore (between 33km and 70km with two parallel cables), a different number of hours invested per platform is expected. For the non-intrusive maintenance, activity mobilisation costs (see section 7.1.1) for the survey vessel are included in the transport/logistics costs.

For the corrective maintenance, a probability-rate is derived and applied for every year of the regulatory period as the need for corrective maintenance can only be estimated based on probabilities for failure. The average failure rate per cable km and year was set at 0.00299 for this estimation, based on the observed mean AC failure rates of European AC offshore grid connections in an essay published in 2019 by John Warnock et al.[39] This failure probability-rate is multiplied by the length of the cable for each platform, resulting in an expected annual failure rate per grid connection system.

TenneT has explained that cable repair costs are included in the insurance but that an own risk of EUR [redacted] applies per event. As it is not yet clear when a cable failure is exactly going to occur, one can only use a probability rate to estimate possible costs for TenneT, which should be considered in the opex allowance for an individual year. The average failure rate per platform as derived above therefore specifies the retention TenneT should bear for each platform (the own risk TenneT has to pay in case of a failure which is not covered by the insurance premium). This approach ensures the appropriate consideration of grid connections with more cable-km, such as the Hollandse Kust West grid connections (see Table 2). DNV GL believes that cable repair costs are likely to be higher than the own risk of EUR [redacted] (mobilisation and demobilisation and day rates for vessels and crews, material, failure rate investigations, etc.). Therefore, cable repair costs per failure event commensurate to the level of the own risk (i.e. EUR [redacted]) are assumed. Pass-through of corrective maintenance costs in the event of a cable failure would be a possible alternative solution.

7.1.2.3 Land Station

For the onshore substation maintenance assumptions, DNV GL has identified six non-intrusive maintenance tasks for high voltage installations and high voltage secondary systems and one intrusive task relevant for the land station.

Table 4: List of maintenance activities at the land station

33 kV AIS
220 kV AIS
Main Transformer 380kV/220kV/33kV (non-intrusive)
Main Transformer 380kV/220kV/33kV (intrusive)

[38] Voorschrift 8, Number 2, Watervergunning voor het aanleggen, gebruiken en verwijderen van het net op zee Hollandse Kust (zuid) van TenneT TSO B.V., Ministerie van Infrastructuur en Waterstaat

[39] J. Warnock, D. McMillan, J. Pilgrim and S. Shenton: Failure Rates of Offshore Wind Transmission Systems. Energies 2019, 12, 2682.

Control and Protection (Battery Upgrades)
Control and Protection (Computer Upgrades)
Communication network (onshore)

The non-intrusive tasks are mainly driven by the quarterly inspection of the 220kV onshore switchgear, while the necessary intrusive maintenance concerns the onshore transformers, expected to be necessary in the fifth year after commissioning of the platform. There are no corrective maintenance activities expected within the first five years concerning the land station.

7.1.3 Costs Not Directly Attributable to a Single Platform

For indirect costs it is important to only consider cost items and activities related to the offshore grid and only cost items which are incremental to the existing costs in the opex allowance. In addition, as some of these activities are of a less standardised nature, different scenarios as to their values are applied.

7.1.3.1 Insurance

As mentioned in section 6.1.2.3, the cost of insurance is difficult to estimate with a bottom-up approach and therefore must be derived from different sources. DNV GL experience shows that an offshore platform in Western Europe of similar size to the Hollandse Kust platforms of 700 MW have insurance cost of around EUR [redacted] per MW, which is very much in the range of other projects of EUR 1,100 – EUR 2,200 per MW for insurance. Other sources like the regulatory accounts statement of the OFTO of Greater Gabbard (for more on the OFTO opex costs see section 4.2) state that their average insurance costs for 2019 and 2020 are at GBP 1.01 million,[40] resulting in an insurance cost per MW of around EUR 2,220[41] for the 500 MW connection.

In its answers to DNV GL, TenneT stated that two types of insurances have been contracted for all parts of the offshore grid (covering the two existing Borssele platforms as well as the new Hollandse Kust platforms once commissioned) a machinery and offshore asset insurance, and a liability insurance. TenneT further stated to have current insurance cost per platform of EUR [redacted], resulting in around EUR [redacted] per MW (each Hollandse Kust platform has 700 MW). [redacted]. The machinery and offshore asset insurance policy of TenneT apparently ends on [redacted], while TenneT's liability insurance of apparently ends on [redacted].

In general, it appears to be difficult to compare the insurances, as policies and the level of insurance might possibly differ by platform. In order to accommodate the resulting uncertainty, we apply scenarios to measure the impact of the insurance costs on the estimated per allowance (see section 7.1.4).

7.1.3.2 Overarching Cost

TenneT reported the following overarching cost items in their submission provided to DNV GL:

1) Operational management
2) Support functions

40 Greater Gabbard OFTO Plc, Regulatory Accounts for the year ended 31st March 2020, p.49

41 Conversion rate of GBP to EUR = 1.1

3) Safety, Health and Environment

4) Controlling / Warranty management

5) IT-Costs & Telecommunication

6) 24/7 Support lines and systems

TenneT explained that items 1) – 4) refer to labour costs of staff employed at different departments of TenneT, while items 5) and 6) relate to services provided by external third parties.

TenneT was asked to clarify to which specific activities these individual cost items refer to, whether these items include only costs related to the offshore grid, to what extent any overhead costs are included in these positions and whether these are all incremental costs (varying with the number of offshore platforms commissioned).

The cost reported by TenneT for operational management of EUR [redacted] relate to all costs for the preparation and planning of maintenance trips and the development and implementation of maintenance plans based on the maintenance strategy of asset management. The support functions amounting to EUR [redacted] per platform and year are according to TenneT supposed to cover data and documentation (for operations), project management for corrective maintenance and stakeholder management (for example contact persons for authorities for survey campaigns). For Safety, Health and Environment (SHE), TenneT has reported costs of EUR [redacted], covering SHE compliance within grid field operations, implementation of SHE concepts through best practices, programs and guidelines, advice and support for grid field operation, risk assessments and ensuring compliance with SHE policies. According to TenneT, controlling relates to the preparation of budgets, reporting and providing financial assistance in discussions with suppliers, whereas warranty management covers the handling of warranty claims related to assets which are within the warranty period; for both items TenneT reported EUR [redacted]. IT costs reported by TenneT cover the licensing costs for IT-systems supporting the monitoring and operation of the offshore platforms, whereas telecommunication costs relate to the communication between the marine operation centre and the platforms (both items account for EUR [redacted] according to TenneT). The reported support lines and systems costs relate according to TenneT to support for the SCADA systems (ensuring the system performance and providing 24/7 assistance if needed); here [redacted] EUR per platform and year have been reported by TenneT.

Within the short timeframe of the project and based on the information provided by TenneT, DNV GL has not been able to determine whether all of the above costs reported by TenneT are incremental costs and to what extent these costs represent an efficient value. For the quantification of the opex allowance they have therefore been considered with their planned values according to TenneT, however adjusting the labour unit costs for the activities conducted by TenneT staff by the estimated labour unit costs as specified in section 7.1.1 (i.e. applying the planned hours as reported by TenneT, but not the labour unit costs reported by TenneT).[42]

7.1.3.3 Other Operational Costs

TenneT specified four not directly attributable "other" operational cost items in their submission to DNV GL:

- Researches & Development and OPEX related to assets under construction

42 IT and telecommunication, as well as 24/7 support lines and systems are provided by external third parties. As no information on the split of labour and non-labour costs for these activities as well as the expected hours required for their conduction has been provided by TenneT, no adjustment for labour unit costs has been conducted for the reported costs of these activities.

- Asset Management
- Land lease agreements
- Allocation of TenneT costs

Research & Development and OPEX related to assets under construction

TenneT explained that these costs include, among others, IT expenses for document control, studies and third-party expertise, communication, personnel and cost improvement initiatives to decrease future investment costs and decrease operational costs for surveys, inspections and maintenance. TenneT furthermore specified that these costs are not incremental but will remain constant over the duration of the regulatory period (except for inflation).

Based on the explanations provided by TenneT, these costs appear not to be incremental and are therefore not included in the estimation of the offshore grid opex allowance.

Asset Management

TenneT specified that the asset management costs relate to the maintenance strategy of the offshore grid, but that these costs will remain at the current level (except for inflation) for the duration of the upcoming regulatory period.

As these costs appear to be not incremental, they are not included in the estimation of the offshore grid opex allowance provided in this section.

Land lease agreements

For the Hollandse Kust Zuid offshore connection, it is expected by TenneT that, contrary to the other connections, a land lease agreement will need to be concluded for the onshore substation. As this is specific for this connection, it is not included in the estimation of the opex allowance provided in this section. We recommend considering these costs separately and to add them on top of the opex allowance for the Hollandse Kust Zuid offshore connections.

Allocation of TenneT costs

In this cost category, the general overhead costs of TenneT allocated to the existing and planned offshore grid segments have been reported by TenneT. In the numbers provided by TenneT to DNV GL, a constant amount based on the current level (only adjusted for inflation) is reported for the upcoming regulatory period. As these costs appear to not be incremental, they are not included in the estimation of the offshore grid opex allowance provided in this section.

7.1.4 Estimation of Opex Allowance

As explained above, the opex allowance is estimated by determining the efficient offshore grid opex in absolute terms per activity or cost item per platform per year, based on which an overall absolute opex allowance in Euro per year and for the duration of the regulatory period is then calculated.

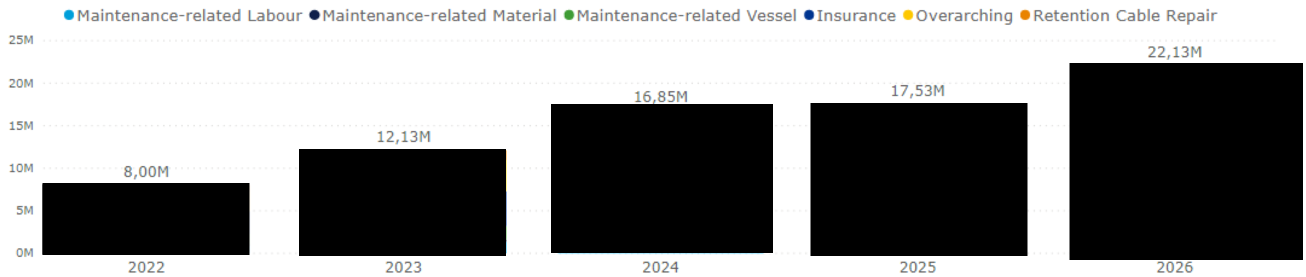
Furthermore, based on the estimation approach outlined throughout the report, three different scenarios for the estimation of an appropriate opex allowance have been prepared. The distinction of the scenarios lies solely in the application of insurance cost and aims to account for the uncertainty related to its estimation (see also sections 6.1.2.3 and 7.1.3.1).

- Scenario 1: The base scenario consists of the current insurance costs provided by TenneT.

- Scenario 2: The low insurance scenario considers lower values for insurance costs per MW as witnessed by DNV GL.
- Scenario 3: The insurance-adjusted scenario applies [redacted].

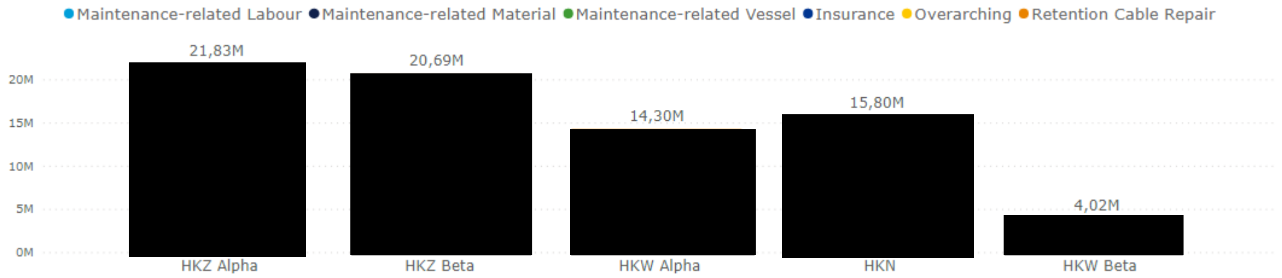
Figure 13 shows the share of each cost category of the expected opex allowance by year. It demonstrates the significant role of the overarching and insurance costs. The total figures increase over time reflecting the subsequent commissioning of Hollandse Kust offshore platforms.

Figure 13: Total opex per year by cost in base scenario (at 2020 price levels)



As the bottom-up estimation is conducted for each of the Hollandse Kust platforms, one can naturally exhibit the opex allowance per platform reflecting the expected efficient opex accrued across the regulatory period according to the respective commissioning dates (see Figure 14).

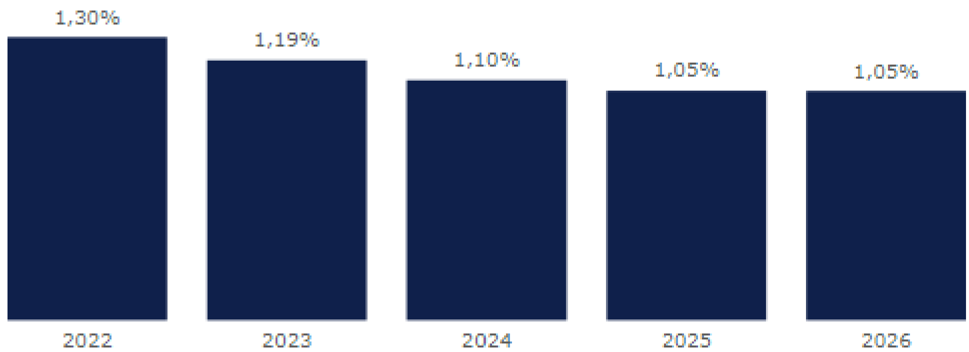
Figure 14: Absolute opex allowance for each Hollandse Kust platform (at 2020 price levels)



The costs of land lease costs (as specified in section 7.1.3.3) for both HKZ Alpha and Beta are not included in the figure above and need to be added individually to the opex allowance in every of the three scenarios presented in this section.

The figure below (Figure 15) shows the annual opex allowance for the base scenario expressed as percentage of capex. The opex percentage allowance is derived when the sum of the respective efficient maintenance costs (i.e. labour, material and transportation costs), insurance, overarching costs and the retention of the cable repair (see section 7.1.2.2) is divided by the summed capex of all platforms commissioned up to and including the respective year, adjusted by the operational months in the respective year. Since the maintenance schedule of all platforms are expected to be quite similar, but the expected capex for each platform is differing, the annual opex percentage allowance varies across the years of the regulatory period. For example, in 2023 (the second year of the regulatory period) the opex allowance and cumulated capex amounts to EUR 12.13 million and EUR 1,017 million respectively. They refer to both HKZ Alpha and Beta and HKN (commissioned in March 2023, see Table 5) whereas the expected capex is adjusted by the months in operation in year 2023. This results in an opex allowance of 1.19% in year 2023 (see Figure 15).

Figure 15: Opex allowance per year in % of capex for base scenario without inflation adjustment



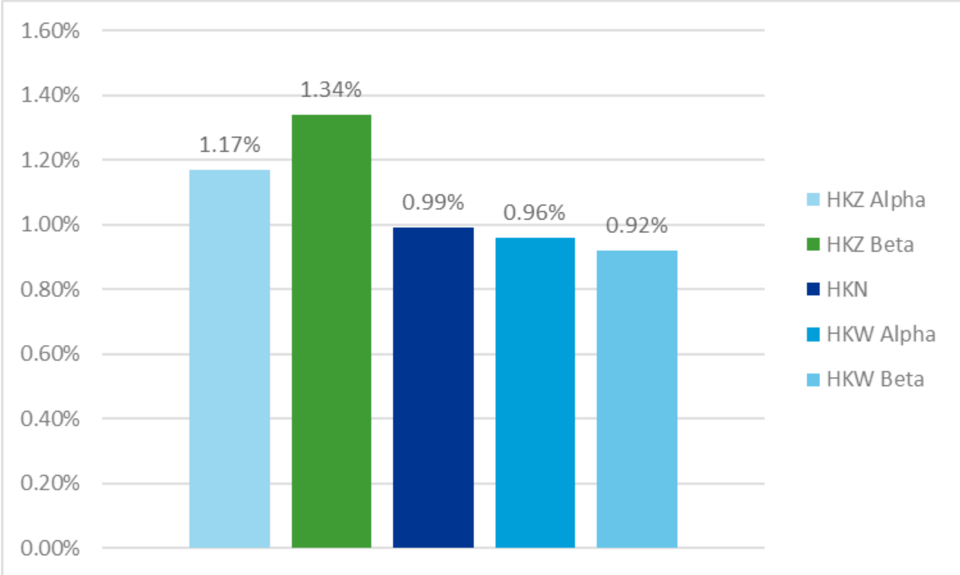
It is possible to establish a uniform annual percentage allowance for the duration of the regulatory period. The calculation of such uniform allowance is conducted in two steps. First, the annual absolute opex allowances are aggregated to establish the total opex allowance for the regulatory period. The total opex allowance is then divided by the aggregated planned weighted capex of the offshore platforms to derive a single average figure for the percentage opex allowance for the regulatory period. The capex weighting accounts for the years the individual platforms are in operation during the regulatory period. For example, an investment that is expected to be commissioned on Jan 1 of the first year of the regulatory period will receive a weight of 5, i.e. it will count five times in the aggregated planned capex. In contrast, an investment that is expected to be commissioned on April 1 of the last year of the regulatory period will receive a weight of 9/12=3/4, i.e. it will count 3/4 in the aggregated planned capex. The uniform annual percentage opex allowance amounts to 1.11 % in the base scenario (Table 5).

Table 5: Calculation of opex allowance for base scenario without inflation adjustment (valued at 2020 levels)

		2022	2023	2024	2025	2026
Cumulated capex	(1)	616,173,476	1,016,870,941	1,530,724,172	1,666,531,270	2,104,525,006
Total opex allowance (conventional)	(2)	8,000,366	12,126,600	16,851,891	17,534,612	22,125,582
Annual opex % allowance	(3)=(2)/(1)	1.30%	1.19%	1.10%	1.05%	1.05%
Average opex % allowance	(4)=∑(2)t=0,5 /∑(1)t=0,5	1.11%	1.11%	1.11%	1.11%	1.11%
Total opex allowance (reprofiled)	(5)=(4)*(1)	6,809,538	11,237,778	16,916,541	18,417,390	23,257,804

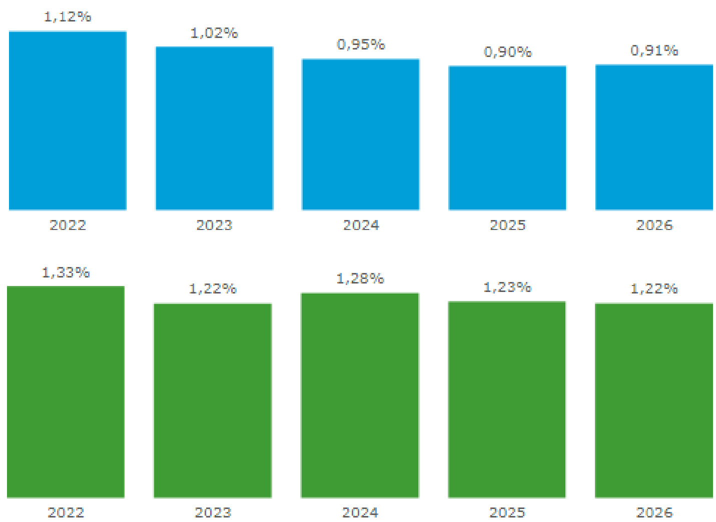
It is also possible to calculate the opex allowance by platform which results in an allowance in percentage of capex between 0.92% and 1.34% (for the base scenario, see Figure 16). This method, however, places a greater weight on the grid connections commissioned at the beginning of the period. Therefore, a consolidation of the figures by time (as in Table 5) leading to a uniform annual percentage opex allowance for the regulatory period appears to be preferable.

Figure 16: Opex percentage allowance calculated separately for each platform (base scenario, at 2020 price level, for the entire regulatory period 2022-2026)



In the low insurance scenario and the insurance-adjusted scenario (future increase of insurance cost), the uniform annual percentage opex allowance (item 4 of Table 5) changes to 0.95% and 1.25%, respectively. This range serves as an indication to what extent the yearly opex necessary for the platforms are dependent on the insurance cost for each grid connection.

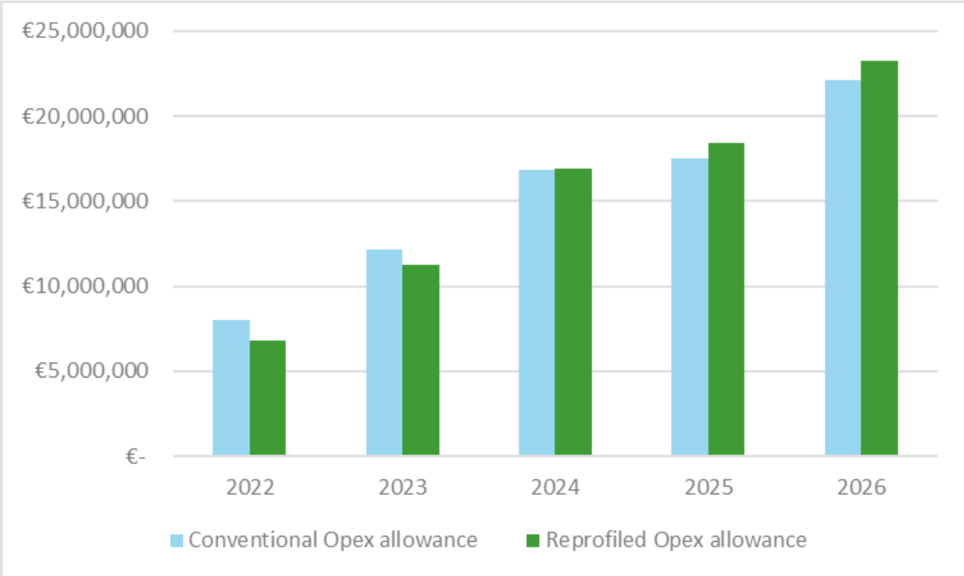
Figure 17: Opex allowance per year for the low insurance scenario (blue bars) and the insurance-adjusted scenario (green bars) without inflation adjustment (at 2020 price level)



The application of the uniform annual percentage opex allowance to the expected capex leads by definition to averaged annual figures of the allowed opex (reprofiled annual absolute opex allowance, item 5 of Table 5).

However, the platforms are characterised by differences in maintenance activities (related to export cable lengths), commission dates and expected capex. These factors can lead to over and under recovery in the single years of the regulatory period ("reprofiling effect") when compared to the annual opex allowance in absolute terms resulting from the activity-based model (conventional annual absolute opex allowance). The reprofiling effect is demonstrated in Figure 18.

Figure 18: Reprofiled opex allowance compared to conventional opex allowance in absolute terms in Euro per year



The light blue bars show the expected opex in Euros based on the activity-based estimations for the specific year (conventional opex allowance), while the green bars show the absolute reprofiled opex allowance. These differences are particularly driven by the profound differences in the expected capex of the Hollandse Kust platforms, ranging from EUR 326 million to EUR 584 million.

With the exception of cable maintenance (due to differing cable length), the maintenance schedule itself remains the same for all platforms. As the platforms are not commissioned at the same time, the opex allowance in absolute terms does not increase in a linear manner.

The "reprofiling effect", however, is balanced throughout the entire regulatory period, ensuring the recovery of the allowed revenue.

To account for price inflation, we index the reprofiled annual allowance assuming a constant stable inflation of 1.5% across the entire regulatory period. The inflation adjustment corresponds to a uniform annual percentage opex allowance, from 1.16% for the base scenario and 1.00% and 1.31% for the "low insurance" and "insurance-adjusted" scenarios, respectively.

About DNV GL

Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil & gas and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 12,700 professionals are dedicated to helping our customers make the world safer, smarter and greener.