Project Title: Refine the allocation of Dynamic Reactive Compensation Equipment (DRCE) costs at OFTO transfer

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Executive Summary

NGESO is responsible for maintaining the voltage on the transmission system within ±10%. This is achieved by a combination of tap changers on transformers and generators Dynamic Reactive Compensation Equipment (DRCE) to provide voltage control via offering reactive power to the system. All generators connected to the transmission system that operate over 46MW are therefore required to have the capability to provide this service, as set out in the Grid Code. This service is compensated via the Obligatory Reactive Power Service (ORPS) for onshore generators but is not available to offshore generators due to the methodology applied in the offshore transmission owner (OFTO) charging framework that allocates ownership of onshore assets to the OFTO.

The current regulatory regime requires the offshore developer to bear the cost of the DRCE installed at the onshore substation. During the OFTO (offshore transmission owner) transaction, the DRCE is transferred to the OFTO owner and paid to the generator via the Final Transfer Value (FTV), which is the basis for the Tender Revenue Stream (TRS). The TRS, including the cost of DRCEs, is fed into the TNUoS offshore local circuit tariff paid by the generator for the lifetime of the asset. However, an offshore wind farm's point of connection (POC) is offshore after the OFTO transaction, and the DRCE is not used for compliance at this POC. Offshore generators are required by the Grid Code to comply with their reactive power obligations at the Offshore POC, and the DRCE is installed onshore to enable the OFTO to comply with its reactive power Grid Code obligation.

There is a commercial defect in the allocation of DRCE costs that is unfairly weighted against offshore generators. Pre-OFTO transaction, the offshore generator is liable to pay for its own reactive compensation requirements offshore by installing shunt/switched reactors and is also liable to pay and build the DRCE onshore. After the OFTO transaction, the offshore generator unfairly continues to pay, via the TNUoS offshore local circuit tariff, for an asset located within the onshore transmission system that is used for OFTO reactive compensation compliance rather than wind farm compliance, and which is also enabling the OFTO to get remunerated for their mandatory reactive power Grid Code requirement.

Given the high capital costs associated with DRCEs, which can reach tens of millions of pounds, the existing allocation of TNUoS charges for offshore generators is inconsistent with CUSC objectives and potentially detrimental to the investment level and growth of the offshore renewable energy sector. The report proposes to remove the DRCE cost component from the TNUoS offshore local circuit tariff, which would establish a parity in the treatment of offshore generators with other types of generators.

Key findings from the report include:

- Reviews of DRCE operation and the current market for reactive power services in Great Britain (GB).
- A review of the additional wider TNUoS costs and reduced offshore wind development costs as a result of this proposed change.
- A review of grid documents, highlighting that socialising DRCE costs across the wider network is more consistent with guidelines.

Based on these findings, we recommend the following:

- Re-evaluate the allocation of DRCE costs, with the recommendation to move these costs to the wider onshore TNUoS tariff, updating NGESO’s “Offshore Local TNUoS Tariff Setting Template” and the OFTO Cost Assessment Template accordingly.
- Amend the CUSC, according to a single modification, to enable the proposed cost allocation changes, ensuring a more equitable distribution of DRCE costs for offshore generators.

Introduction and Purpose of this Report

The purpose of this report is to explore the purpose of Dynamic Reactive Compensation Equipment (DRCE), their treatment in Transmission Network Use of System (TNUoS) charging and whether this is consistent with relevant Connection and Use of System Code (CUSC) objectives. In this report, we focus on their role in providing reactive power services in the context of offshore wind farms and the CUSC, while we argue that moving DRCE costs to wider onshore TNUoS tariff is not only more consistent with CUSC objectives, creates an equitable treatment with onshore assets, and is beneficial for promoting renewable energy investments.

DRCEs are defined as Plant and Apparatus capable of injecting or absorbing Reactive Power in a controlled manner which includes but is not limited to Synchronous Compensators, Static Var Compensators (SVC), or STATCOM devices. They are indispensable components in power systems, especially for offshore wind farms, as they provide reactive power compensation and help maintain grid stability. Reactive power is crucial for ensuring voltage levels remain within acceptable limits and is required for the reliable and efficient operation of power systems. Currently, all HVAC-connected offshore wind farms require DRCEs to meet grid code compliance concerning reactive compensation.

However, the costs of these crucial devices are high, with prices reaching tens of millions of pounds. Due to supply chain constraints and global factors, the costs of DRCEs have recently seen significant further increase. At present, DRCEs are considered part of the Offshore Transmission Owner (OFTO) asset and are included in the asset transfer process as part of the Final Transfer Value (FTV), which is the basis for the Tender revenue Scheme (TRS). Following asset transfer, the generator pays the OFTO for the DRCEs through the offshore local circuit tariff.

It is crucial to emphasise that DRCEs are required for the OFTO to comply with its reactive power Grid Code requirement, given that an offshore wind farm's point of connection (POC) is offshore, and the DRCE is not utilised for compliance at this POC.

Moreover, the change in approach and change in the allocation of DRCE costs is consistent with CUSC objectives because it promotes a more equitable distribution of costs and benefits. The cost for the provision of reactive compensation by onshore windfarms is remunerated via the ORPS payment, this is funded by Balancing Services Use of System (BSUoS) charges, which is paid by demand. The modification proposed under CMP 418 would harmonise the treatment between onshore and offshore generators as the cost for the provision of reactive compensation by OFTOs would now be funded by demand through the Transmission Demand Residual (TDR) instead of the offshore generator. Accordingly, the proposed solution under CMP 418 facilitates effective competition in the generation of electricity while also encouraging the development of renewable energy sources, and potentially lowering energy prices. This aligns with the CUSC's objectives of fostering a competitive market, supporting the transition to a low-carbon energy system, having charges that accurately reflect the costs incurred by transmission licensees, lowering energy bills and carbon emissions, and providing UK jobs to facilitate the increased number of offshore wind projects. The remainder of this report analyses the operation of DRCEs in offshore wind farms, the reactive power market in the context of offshore wind, and sets out the CUSC modification proposal to implement the proposed change.

OFTO Transfer Process

The OFTO transfer process involves several steps:

1. Development and Construction: The offshore wind farm developer designs, builds, and commissions the transmission assets necessary to connect the offshore wind farm to the onshore grid. These transmission assets typically include subsea cables, onshore and offshore substations, and converter stations if HVDC transmission is used.
2. OFTO Tender Process: Once the offshore transmission assets have been commissioned and are operational, the developer sells these assets. This is done through a competitive tender process which is administered by Ofgem, with the winning bidder becoming the OFTO for those assets. The aim of this process is to drive down the cost of offshore transmission and ultimately reduce the cost of offshore wind energy.
3. Transfer of Ownership and Operation: The OFTO takes over the ownership, operation, and maintenance of the transmission assets. The OFTO receives a regulated income via the TRS over a 25-year period for providing these services, subject to meeting certain performance requirements. The TRS drives the local circuit/substation TNUoS, which is borne by the generator.

The ownership boundaries of the wind farm/generator, OFTO, and onshore network operator are shown in Figure 1.

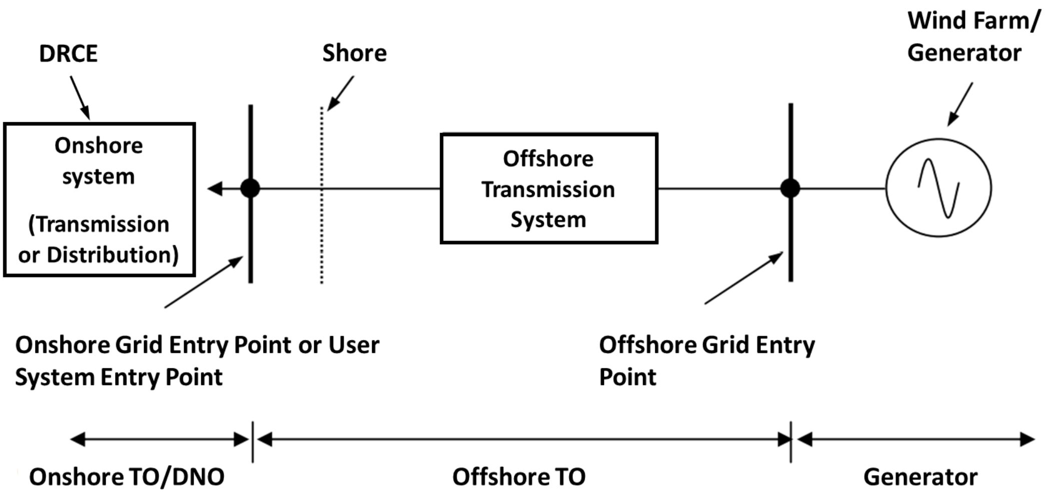

Figure 1 - Designation of offshore wind farm boundaries.[1]

During the asset transfer process, assets are broken down into various categories, as shown in Table 1 below. The primary categories that are paid for by the generator are the local substation and local circuit tariffs. Currently, DRCE is included within “Reactive Equipment” as part of the Local Circuit Tariff.

[1] Offshore Transmission Expert Group — Great Britain Security and Quality of Supply sub-group. Recommendations for the coverage of offshore transmission networks in the Great Britain Security and Quality of Supply Standard, 2006

Table 1 - National Grid Offshore Asset Cost Allocation Guidance

Tariff	Asset Category	Description	Payments
LOCAL CIRCUIT TARIFF	Cable Assets	All electrical assets between the cable sealing ends of transmission voltage cables owned by the OFTO which run to/from a substation/platform, including jointing and the cable sealing ends, excluding assets defined as Reactive Equipment.	Generator
	Reactive Equipment	All Reactive Compensation Equipment and associated electrical and non-electrical equipment up to (but excluding) the last piece of switchgear prior to the connecting busbar, Cable Asset (as defined below), or tertiary transformer winding. Currently, this includes DRCE. In the proposed modification, the DRCE would be excluded from this category.	
	Harmonic Filtering Equipment	All Harmonic Filtering Equipment and associated electrical and non-electrical equipment up to (but excluding) the last piece of switchgear prior to the connecting busbar.	
	HVDC Converter Station	HVDC Conversion Equipment and all connecting electrical assets between (but excluding) the adjacent AC disconnector and the connecting HVDC Cable Assets.	
LOCAL SUBSTATION TARIFF	Transformer Assets	Each transformer not classified as Reactive Compensation or Auxiliary Supply Equipment and all associated assets between (but excluding) the adjacent disconnectors. This includes items such as cooling equipment and bushings.	Generator
	Switchgear Assets	Any Circuit Breaker, Disconnector, or Earth Switch.	
	Platform	Any assets associated with or residing on the offshore platform, not specified in other asset/cost categories. These include the basic floating platform structure, housing of the electrical equipment, electrical equipment, protection equipment, buildings, fire prevention, transportation facilities (e.g., helipads), environmental protection equipment, and the cost of any associated civil works.	
	Auxiliary Supply Equipment	Any electrical equipment with the sole purpose of supplying power for the operation of the offshore platform or onshore substation	
ASSET DEPENDENT	Contingency	The level of contingency included within the asset transfer value in relation to each category and location of potential use (onshore/offshore) as individual entries.	Asset-Dependent
	Spares	Any spare equipment as a cost associated with the asset which it will replace	

	Other costs (for very limited use if at all)	The value of any assets/costs, with a transfer value in excess of £50k, which cannot be allocated to any of the categories listed.	
ETUoS	DNO Costs	Any payments made to DNOs included within the asset transfer value that relate to works on distribution networks to facilitate the offshore project including connection and deeper reinforcement works.	Generator
ONSHORE	Onshore Substation	Any assets associated with or residing within the onshore substation, not specified in other asset/cost categories. These include the cost of the substation structure, fencing, housing of the electrical equipment, electrical equipment, protection equipment, buildings, fire prevention, transportation facilities (e.g. roads), environmental protection equipment, and the cost of any associated civil works. In the proposed modification, this category would include DRCE.	All Transmission Users — payment split from ~ 77% demand & ~ 23% generation

Operation of DRCEs in Offshore Wind Farms

DRCEs are essential components in wind farms, especially for offshore installations, as they provide dynamic reactive power compensation and contribute to the overall stability of the electricity network. Reactive power compensation is crucial for maintaining voltage levels within acceptable limits, ensuring the reliable and efficient operation of power systems.

The Grid Code sets out the mandatory reactive compensation requirements for offshore generators and offshore transmission owners (OFTO).

The wind farm must adhere to the Grid Code's technical, design criteria, and performance requirements (Issue 6, revision 16 – 5 January 2023) [2]concerning reactive power capability and both steady-state and transient voltage control. Specifically, ECC.6.3.2.5.1 sets out the requirement that the wind farm must:

- Maintain zero reactive power transfer at the Onshore Interface Point (IP) at all active power levels under steady-state voltage conditions, with a steady-state tolerance no greater than 5% of the Rated MW.

This requirement is met by using a combination of offshore generator reactive power capability (Wind Turbine Generators (WTG)) to compensate for the inductance of the inter-array cables and achieve zero reactive transfer at the offshore grid entry point. Fixed shunt reactors (or potentially a combination of fixed shunt reactors and switched reactors) are used by generators to compensate for cable capacitance of the offshore export cables.

ECC.6.3.2.4.4 sets out the requirement that the OFTO must:

[2] National Grid ESO, The Grid Code, 2023

- Supply the rated MW output between the limits of 0.95 power factor lagging and 0.95 power factor leading at the onshore interface point, with the former requiring absorption of Vars from the grid and the latter requiring the injection of Vars.
- The reactive power limits defined at rated MW at lagging power factor will apply at all active power output levels above 20% of the rated MW output as defined in Figure 2.
- The reactive power limits defined at rated MW at leading power factor will apply at all active power output levels above 50% of the rated MW output as defined in Figure 2.
- The reactive power limits will reduce linearly below 50% Active Power output as shown in Figure 2.
- These reactive power limits will be reduced pro rata to the amount of plant in service.

These requirements are met through the use of DRCE. In the case of onshore assets and in some configurations with very short cable lengths (e.g. 0.5 miles), wind turbine generators (WTGs) may provide some contribution to the onshore reactive power requirements in combination with the DRCE. This is not achievable for the large majority of offshore wind farms (as these assets are all located much further than 0.5 miles from shore). The DRCE is then used to achieve the OFTO ±0.95 p.f. Grid Code requirement at the Onshore Interface Point under steady state and dynamic conditions. The absorption or delivery of reactive power from the DRCE is continuously adjusted to meet the Interface Point requirement for reactive power flow.

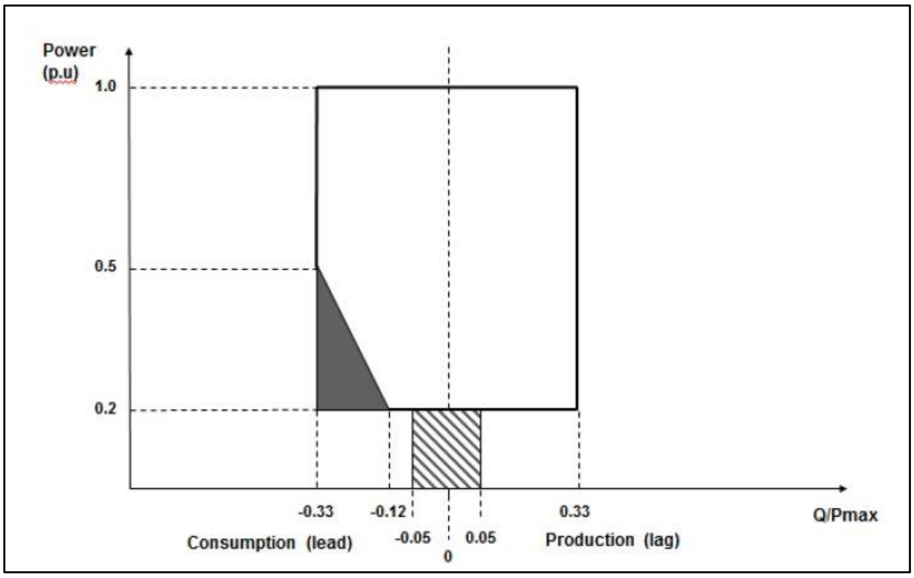

Figure 2 - Reactive power capability requirements of an offshore wind farm.[2]

The onshore reactive power requirements are placed on the OFTO rather than the offshore wind farm because it is not efficient for the wind farm to comply with the normal generator dynamic reactive compensation requirements offshore due to the long offshore export cable lengths.

Reactive Power Market in the Context of Offshore Wind

To provide further evidence for a more equitable distribution of costs associated with DRCE within offshore wind farm systems, we have investigated the reactive power market and the trend in requirement for reactive power services. This section provides technical evidence that highlights the inconsistency of the current approach with CUSC objectives, and the unfair burden currently placed on generators for paying for the DRCE through the local circuit TNUoS, despite the lack of compensation received by the offshore generator and DRCE utilisation for OFTO compliance rather than offshore wind compliance at the offshore POC.

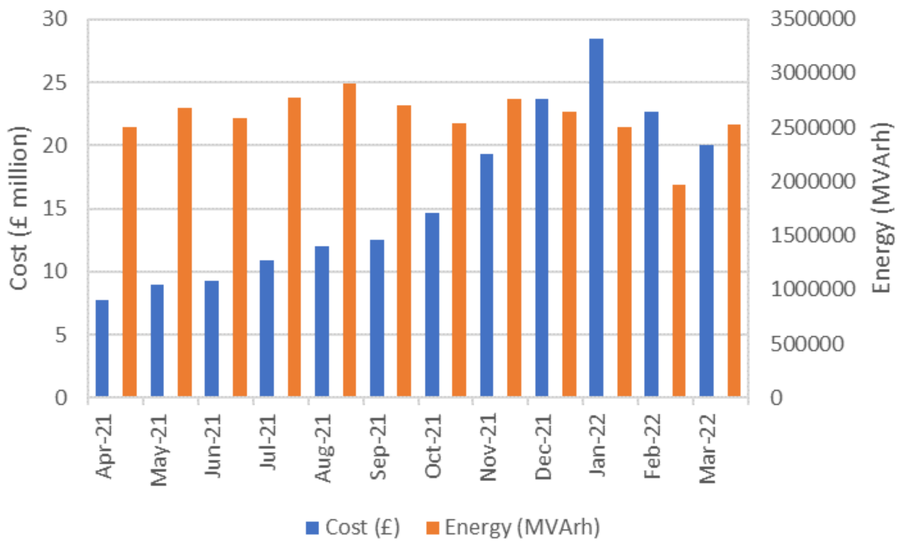

Figure 3 - Monthly cost and amount of reactive energy provision for the 2021–2022 financial year. Adapted from Monthly Balancing Services Summary report for March 2022.[3]

Based on Monthly Balancing Services Summary (MBSS) reports[3] for the past 5 financial years (April 2018–Feb 2023), the total amount paid out in each financial year was £81.73m, £64.87m, £65.07m, £190.15m, £369.02m from oldest to most recent data respectively, while total reactive energy provided was 24.61, 23.60, 26,16, 31.07, 33.85 MVArh.

It is clear from the historic data that the value and amount of reactive power services are both substantial and quickly increasing in recent years, with a 37.5% increase in reactive power provided compared to 5 years ago, while the total payments have increased over four and a half times. Despite the fact that the cost for reactive power services was driven by geopolitical, pandemic, and weather factors, overall payments will remain high due to the increasing volume of services required.[4]

Supporting this historic data is the System Operability Framework's "Operability Strategy Report" for 2023[5], which defines the operational requirements and future system needs to achieve a zero-carbon electricity system by 2035 and states "more reactive power capability and utilisation are required as the reactive power requirement continues to increase and available capacity decreases". The report identifies the following drivers of increasing reactive power needs:

- Transmission circuits, which are lightly loaded, are producing reactive power and increasing voltages.
- Transmission circuits are increasingly being installed underground, which due to their close proximity, have large capacitances — producing reactive power and increasing voltages.
- Reactive power was historically consumed by distribution networks but is now produced by them — also increasing voltages.

[3] National Grid ESO, Monthly Balancing Services Summary (MBSS), 2018–2023
[4] European Central Bank, Energy price developments in and out of the COVID-19 pandemic – from commodity prices to consumer prices, 2022
[5] National Grid ESO, Operability Strategy Report 2023

These three drivers of reactive power production have resulted in largely inductive (lead/absorption) utilisation in recent years, as shown in Figure 4.

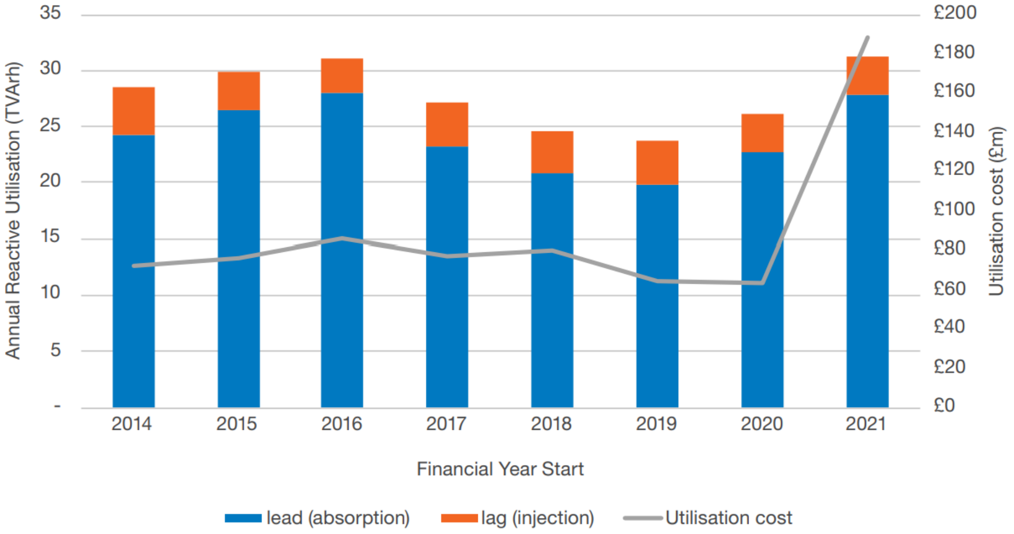

Figure 4 - Graph of annual mandatory (obligatory) reactive utilisation from 2014–2021.[5]

The mandatory/Obligatory Reactive Power Service (ORPS) is the required reactive power provision from generators above 46MW, as set out in Figure 2. The Enhanced Reactive Power Service is the additional service provided beyond the capabilities required by the grid code and are provided through tenders. Both of these services can be compensated with the payment mechanisms shown in Table 2 below.

Table 2 - Description of Obligatory and Enhanced Reactive Power Services.

	Service	Description	Payment Mechanism	Required by
Reactive Power	Obligatory /Mandatory Reactive Power	The Obligatory Reactive Power Service is the provision of mandatory varying Reactive Power output. At any given output the Generators may be requested to produce or absorb reactive power to help manage system voltages close to its POC. The provision of reactive power allows Power Factor Control and Voltage Control by the System operator.	Under the Default Payment Mechanism, National Grid pays all service providers for utilisation in £/MVArh. This is funded via BSUoS.	Generally, all transmission connected generators over 46MW are required to have the capability to provide this service, as set out in the Grid Code
	Enhanced Reactive Power	Enhanced Reactive Power Service is the provision of: Voltage support which exceeds the minimum technical requirement of the Obligatory Reactive Power Service (including Synchronous Compensation); or Reactive Power Capability from any other Plant of Apparatus which can generate of absorb Reactive Power (including Static Compensation equipment) that isn't required to provide the Obligatory Reactive Power Service.	The Enhanced Reactive Power Service is procured via tenders. The tender allows the Generator to request: An Available Capability Price (£/Mvar/hr) and/or a Synchronised Capability Price (£/Mvar/hr) and/or a Utilisation Price(£/Mvarh). The choice of term from a minimum period of 12 months and thereafter in 6-month increments (12, 18, 24, 30, 36 months, etc,).	Any Generator of any size that can meet the technical requirements.

However, the offshore wind farm does not receive reactive power payments for reactive power services provided by DRCEs, despite the heavy investment in this equipment and the continued payment for the assets via the local circuit tariff. Instead, OFTOs are indeed remunerated for reactive power services as part of the OFTO base transmission revenue, not the ORPS, as confirmed by NGESO.

Proposed CUSC Modification

The cost allocation of DRCEs is neither codified nor specifically mentioned in the CUSC document, and implementation of costs is thus an interpretation applied by NGESO. In order to identify the necessary modifications to the CUSC to reflect this proposed change, we have reviewed the full CUSC for any paragraphs relating to reactive power services as well as the CUSC Section 14 "Charging Methodologies" section. We have subsequently examined their relevance to this proposed change. Due to the lack of codification of DRCE cost allocation, only one required change has been found. There are no other obvious changes to the CUSC other than the change proposed for the charging statement (paragraph 14.15.80). We additionally provide rationale for why changes are not required for a further ten paragraphs associated with DRCE operation. Further minor updates to NGESO's Offshore Local TNUoS Tariff Setting Template and the OFTO Cost Assessment Template will be required accordingly.

The improved facilitation of CUSC objectives arising from this change in interpretation of cost allocation includes positive impacts related to facilitating a competitive market, supporting the transition to a low-carbon energy system, lowering energy bills and carbon emissions, and generating employment opportunities in the UK to accommodate the growth in offshore wind projects. However, the full description of the impact on CUSC objectives will be contained in the associated CUSC Modification Proposal Form.

Impact on wider TNUoS Charges

This Annex considers the cost impact on wider TNUoS charges of CMP 418. As confirmed by the ESO, Local Circuit and Substation Charges are classed as Connection Assets and therefore should be excluded when calculating how much revenue can be collected from Generators under the EU Cap. This means that any changes to the Connection Exclusion amount affects the Transmission Demand Residual (TDR).

The impact on TDR is achieved by looking at the amount related to Dynamic Reactive Compensation Equipment (DRCE) that is, under the status quo, recovered by the offshore local circuit tariff. In line with the purpose of CMP 418, if the offshore generator no longer pays for DRCE, then the amount of the OFTO revenue which accounts for that equipment moves from the offshore local circuit tariff to the Transmission Demand Residual (TDR) tariffs (spread proportionally across all TDR tariffs).

The UK has set an ambitious target of reaching 50 GW of offshore wind capacity by 2030[6], and up to 125GW by 2050[7]. As of December 2023, the UK has approximately 15 GW[8] of offshore wind capacity, which would mean 35 GW is required in the 6 years from 2025 to 2030. To meet the 2030 target, it is necessary to add approximately 5.83 GW per year, while approximately 3.75 GW additionally capacity is required annually from 2030 onwards to meet the 2050 target. The number of DRCEs required to support this new offshore wind capacity has been estimated by considering SVCs specifically. SVCs were used as costs were readily available, but STATCOMs are also used as DRCE in offshore wind.

[6] Offshore Wind Net Zero Investment Roadmap, HM Government, 2023
[7] Climate Change Committee (2020), 'The Sixth Carbon Budget: The UK's path to Net Zero'
[8] Wind Energy Statistic, renewable UK

Including different types of DRCE in the analysis would be expected to further improve the benefits of this proposed solution. This is because the same cost-saving calculations used for SVCs are applicable to the typically higher costs of other DRCE equipment.

Each SVC is assumed to cost £17.9m for 100 MVar[9], which is capable of supporting roughly 300 MW of offshore wind (£/MW 59,667). This cost was arrived at by using the mid-range 100MVar SVC cost from ETYS 2015 – Appendix E and inflating to pre-Covid prices in 2020[10].

In status quo, the Tender Revenue Stream (TRS) attributable to SVCs would be recovered through project specific offshore tariff but they in effect represent the amount that would then have to be moved to TDR in line with the recommendation of this CUSC modification and would cover both CAPEX and OPEX. Hence, to calculate the amount that would need to be recovered from TDR, the TRS/Final Transfer Value (FTV) ratio was used to derive the TRS impact. The TRS/FTV ratio is a useful figure to compare the annual amount paid to OFTOs relative to the total offshore transmission CAPEX across projects. An analysis of all TRS data available for wind OFTOs between 2011 and 2021 indicates a stabilisation of TRS/FTV ratio at 4% from Tender Round 6 onwards.[11]

$$TRS\ Impact\ = \frac{TRS}{FTV} Ratio\ \times (Cum.OW\ MW\ x\ SVC \frac{\text{£}}{\text{MW}} cost\ )$$

$$Pre\ 2030\ TRS\ Impact\ (2025)\ = 4\%\ \times (5833\ x\ \times 59{,}667)\ = \text{£}13.92\text{m}$$

$$Post\ 2030\ TRS\ Impact\ (2025)\ = 4\%\ \times (3750\ x\ \times 59{,}667)\ = \text{£}8.95\text{m}$$

	Cum. OW (MW)	Cum. SVC Cost (£)	TRS Impact (£)
2025	3,500	208,833,333	8,353,333
2026	7,000	417,666,667	16,706,667
2027	10,500	626,500,000	25,060,000
2028	14,000	835,333,333	33,413,333
2029	17,500	1,044,166,667	41,766,667
2030	21,000	1,253,000,000	50,120,000
2031	24,500	1,461,833,333	58,473,333
2032	28,000	1,670,666,667	66,826,667
2033	31,500	1,879,500,000	75,180,000
2034	35,000	2,088,333,333	83,533,333

[9] ETYS 2015 - Appendix E, 2015
[10] Bank of England Inflation Calculator
[11] Footnote required by Aurora work, awaiting consent

2035	38,500	2,297,166,667	91,886,667
2036	42,000	2,506,000,000	100,240,000
2037	45,500	2,714,833,333	108,593,333
2038	49,000	2,923,666,667	116,946,667
2039	52,500	3,132,500,000	125,300,000
2040	56,000	3,341,333,333	133,653,333
2041	59,500	3,550,166,667	142,006,667
2042	63,000	3,759,000,000	150,360,000
2043	66,500	3,967,833,333	158,713,333
2044	70,000	4,176,666,667	167,066,667
2045	73,500	4,385,500,000	175,420,000
2046	77,000	4,594,333,333	183,773,333
2047	80,500	4,803,166,667	192,126,667
2048	84,000	5,012,000,000	200,480,000
2049	87,500	5,220,833,333	208,833,333
2050	91,000	5,429,666,667	217,186,667

Impact on Wind Farm Development Costs

The impact of the proposed solution to socialize costs through the TNUoS on wind farm development costs can be seen as twofold: a direct impact that mirrors the increase in TNUoS costs, and an indirect benefit stemming from reduced volatility and financial uncertainty.

Since offshore wind projects participate in the Contracts for Difference (CfD) scheme, which provides a long-term guarantee on price per MWh, these savings have the potential to reduce the CfD price by an amount equal to the annual saving. The costs paid by wind farms would decrease by the same amount paid through wider TNUoS. Assuming 35/110 GW of offshore wind is added by 2030/2050, this would cost up to £83.53m/£262.53m annually to fund via the current methodology. Across 8760 hours in a year and assuming a 45% load factor, this offshore generator annual cost saving is equivalent to £0.61/MWh. This is compared to current offshore wind CfD prices in the latest allocation round of £45.37/MWh.[12]

[12] CfD Register, Low Carbon Contracts

Reducing the unpredictability of TRS payments by removing DRCE costs, provides a reduction in financial risk for developers, leading to higher lower financing costs and reducing potential mispricing in CfD auctions. This is supported by analysis by NERA Economic Consulting[13], which suggests that reduced volatility and improved financial planning could lead to decreased costs to consumers. The proposed solution would thus lead to a net decrease in consumer costs compared to the current methodology that is directly reflective of the DRCE cost that would be socialised via TNUoS, hence we would expect the consumer impact of the proposed change to be net off.

CUSC Modification Analysis

The table below provides the list of CUSC clauses that have been analysed for potential required amendments.

Table 3 - CUSC Modification Analysis

Proposed CUSC Modifications			
Paragraph Number	**Potential changes (highlighted with red text)**	**Rationale**	**Change Required?**
4.1.2.3	In respect of **Generating Unit(s)** located **Offshore** where the **Obligatory Reactive Power Service** is provided to **The Company** by an **Offshore Transmission Licensee** in accordance with the **STC**, the **Mandatory Ancillary Services Agreement** shall detail the payments that **The Company** shall make to the **User** (not withstanding that the **Obligatory Reactive Power Service** is provided to **The Company** by an **Offshore Transmission Licensee.**	This paragraph is regarding provision at the offshore interface only. Thus, no modifications are required.	No.
4.1.2.9	It is acknowledged by **The Company** and each **User** that the provision by that **User** of the **Obligatory Reactive Power Service** in accordance with the terms of the **CUSC** and the **Mandatory Services Agreement** shall not relieve it of any of its obligations set out in the **Grid Code** including without limitation its obligation set out in **Grid Code CC** 8.1 to provide **Reactive Power** (supplied otherwise than by means of synchronous or static compensators except in the case of a **Power Park Module** where synchronous or static compensation within the **Power Park Module** may be used to provide **Reactive Power**) in accordance with **Grid Code CC** 6.3.2.	Cost allocation changes will have no impact on technical requirements and the user will still need to fully adhere to the grid code requirements. Thus, no modifications are required.	No.
14.15.80 (charging statement)	Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner	This is where we exclude DRCE from TRS calculation.	Yes

[13] Offshore Wind Transmission Charges, Scottish Hydro Electric Transmission, September 2021

	and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner’s reactive compensation equipment (excluding DRCE), harmonic filtering equipment, asset spares and HVDC converter stations.		
Schedule 2, exhibit 4, 3.1	The provisions of this Clause 3 implement the terms of Paragraph 2 of Schedule 3, Part I to the **CUSC** (“**CUSC Schedule**”) with respect to the payments to be made by **The Company** to the **User** for the provision by the **User** from the **BM Units** of the **Obligatory Reactive Power Service**, and in accordance with Paragraph 2.1 thereof the **Parties** hereby agree to make all necessary amendments to this **Mandatory Services Agreement** so as to give effect to the provisions of the **CUSC Schedule** as amended or modified from time to time.	This paragraph is irrelevant, since it is talking about the generator. Thus, no modifications are required.	No.
Appendix 1 — Data Section A(Reactive Power)	See section for relevant tables.	This section is irrelevant, because it is for the offshore grid entry point, while the DRCE is located onshore. Thus, no modifications are required.	No.
Schedule 3, Part 1, 1.1	For the purpose of this Part I and the Appendices, “**Obligatory Reactive Power Service**” means the **Mandatory Ancillary Service** referred to in **Grid Code CC** 8.1 which the relevant **User** is obliged to provide (for the avoidance of doubt, as determined by any direction in force from time to time and issued by the **Authority** relieving a relevant **User** from the obligation under its **Licence** to comply with such part or parts of the **Grid Code** or any **Distribution Code** or, in the case of **The Company**, the **Transmission Licence** as may be specified in such direction) in respect of the supply of **Reactive Power** (otherwise than by means of synchronous or static compensation except in the case of a **Power Park Module** where synchronous or static compensation within the **Power Park Module** may be used to provide **Reactive Power**) and in respect of the required **Reactive Power** capability referred to in **Grid Code CC 6.3.2.** This **Mandatory Ancillary Service** shall comprise, in relation to a **Generating**	The referenced Grid Code CC 6.3.2 states “ Offshore Power Park Modules must be capable of maintaining: “…“ the Reactive Power capability (within an associated steady state tolerance) specified in the Bilateral Agreement if any alternative has been agreed with the GB Generator, Offshore Transmission Licensee and The Company”. The required provision of reactive power can therefore	No.

	Unit, **DC Converter** or **Power Park Module** compliance by the relevant **User** in all respects with all provisions of the **Grid Code** applicable to it relating to that supply of **Reactive Power** and required **Reactive Power** capability, together with the provision of such despatch facilities (including the submission to **The Company** of all relevant technical, planning and other data in connection therewith) and metering facilities (meeting the requirements of Appendix 4), and upon such terms, as shall be set out in a **Mandatory Services Agreement** entered into between **The Company** and the relevant **User**. For the avoidance of doubt, "**Obligatory Reactive Power Service**" when used in this Part I and the Appendices excludes provision of **Reactive Power** capability from **Synchronous Compensation** and from static compensation equipment (except in the case of a **Power Park Module** where synchronous or static compensation within the **Power Park Module** may be used to provide **Reactive Power**, and the production of **Reactive Power** pursuant thereto.	be specified in the Bilateral Agreement and does not need to be specified here. Thus, no modifications are required.	
Appendix 8, Part 3	In accordance with the terms of the **Mandatory Services Agreement**, where applicable the formulae in Section 1 of this Part 3 will be used by **The Company** to convert **Reactive Power** capability of a **Power Park Unit** at the generator stator terminals to the capability at the HV side of the **Generating Unit** step-up transformer, and the formulae in Section 2 of this Part 3 will be used to calculate the **Reactive Power** capability of the **Power Park Module** at the **Commercial Boundary**.	Commercial boundary and technical capabilities/requirements would be unchanged. Thus, no modifications are required.	No.

Appendices

Appendix A: Monthly Costs and Provision of Reactive Energy for 2018—2023

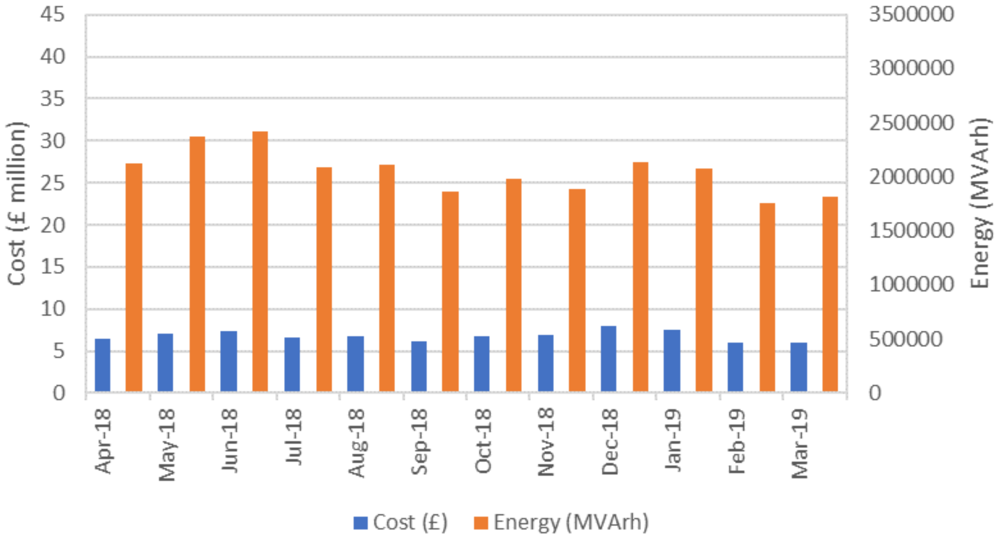

Figure 5 - Monthly cost and amount of reactive energy provision for the 2018–2019 financial year. Adapted from Monthly Balancing Services Summary report for March 2019 [1].

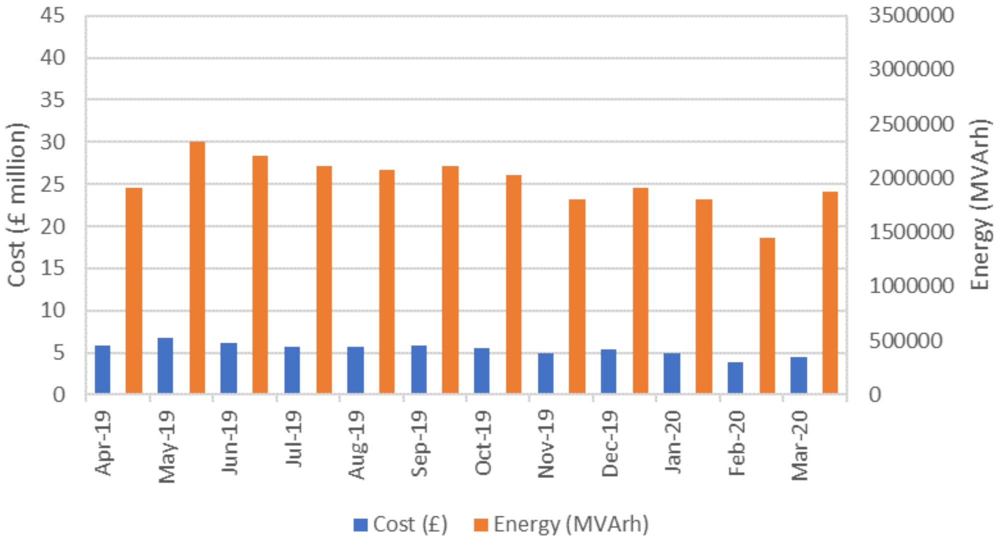

Figure 6 - Monthly cost and amount of reactive energy provision for the 2019–2020 financial year. Adapted from Monthly Balancing Services Summary report for March 2020 [1].

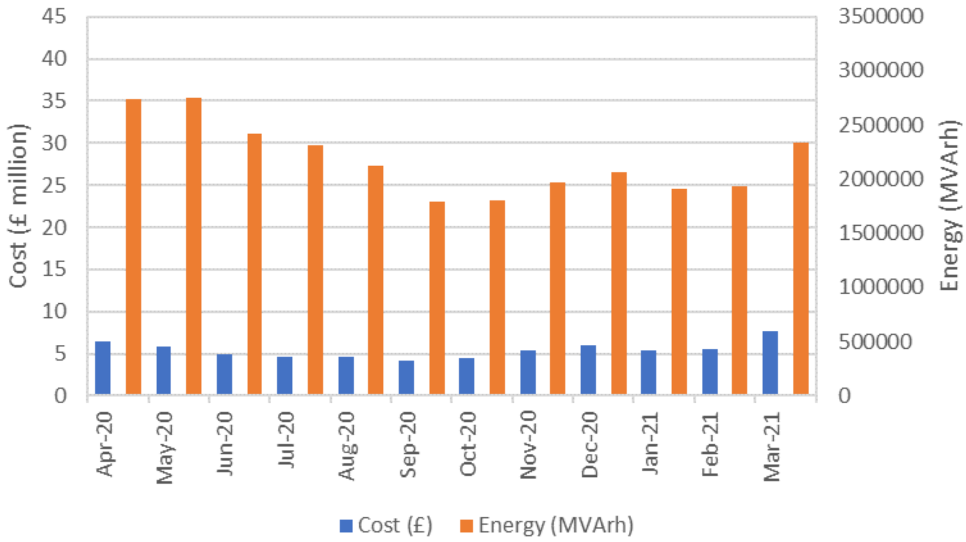

Figure 7 - Monthly cost and amount of reactive energy provision for the 2020–2021 financial year. Adapted from Monthly Balancing Services Summary report for March 2021 [1].

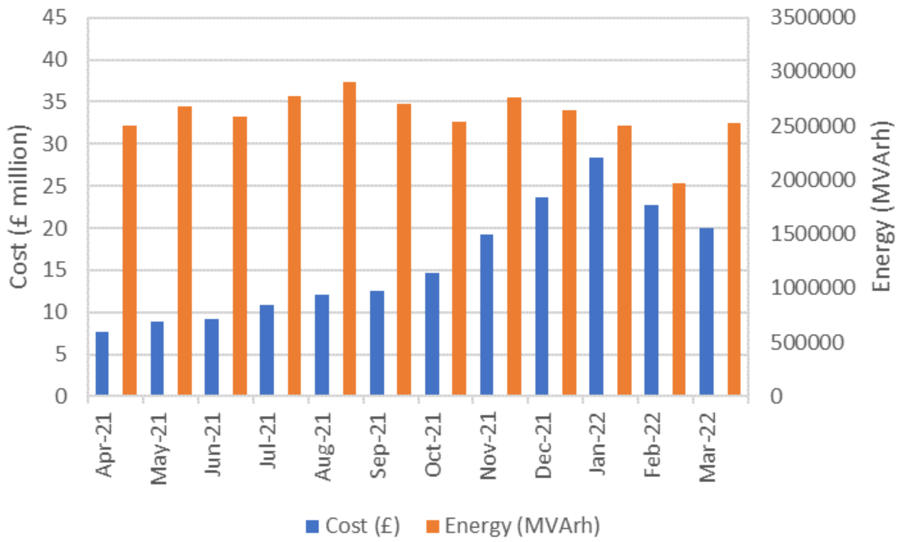

Figure 8 - Monthly cost and amount of reactive energy provision for the 2021–2022 financial year. Adapted from Monthly Balancing Services Summary report for March 2022 [1].

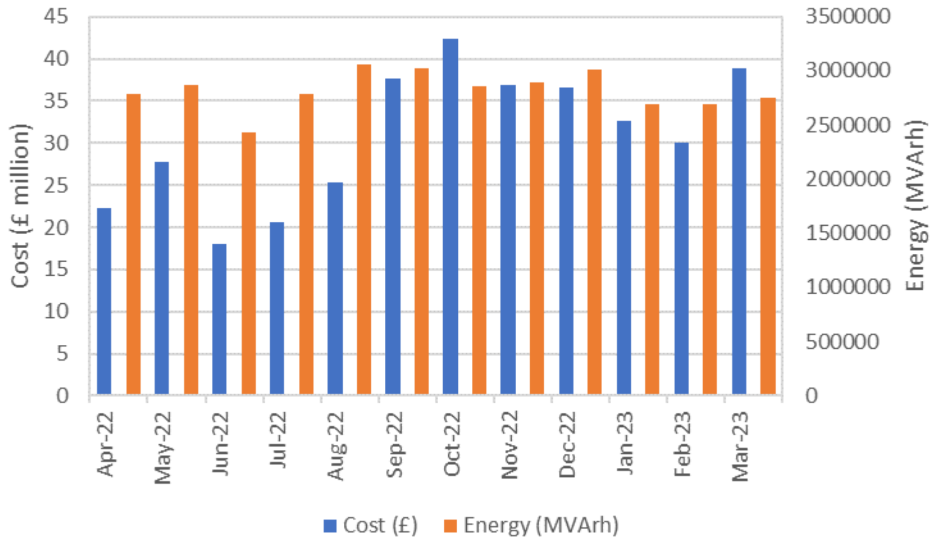

Figure 9 - Monthly cost and amount of reactive energy provision for the 2022–2023 financial year. Adapted from Monthly Balancing Services Summary report for February 2023, and March values were forecasted [1].