

CMP344 Modification Development Support

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Executive summary

Overview

RWE commissioned Cornwall Insight to analyse the impact of the treatment of transmission network use of system (TNUoS) charges and potential Income Adjusting Events (IAEs) at offshore wind generators and the implications these have for consumers.

The CUSC modification proposal CMP344 *Clarification of Transmission Licensee Revenue Recovery and the Treatment of Revenue Adjustments in the Charging Methodology* proposes that the additional revenue allowances for Offshore Transmission Owners (OFTOs) in relation to IAEs should be recovered from all demand users, rather than just the generator directly affected. In this report, we consider the implications that this would have for TNUoS charges and the effects on Contract for Difference (CfD) strike prices.

Our key conclusions are that:

- IAE claims have been rare, and none have been approved by Ofgem so far. Even so, the risk of IAEs occurring is likely to be impacting the prices ultimately paid by consumers.
- Based on generators taking an assumption of a 1 in 50 chance of an IAE with a £10mn TNUoS impact occurring in any given year, we estimate the TNUoS risk of IAEs for generators increases CfD strike prices by £0.03/MWh. For anticipated AR5/6/7 assets alone, the total benefit to consumers of applying CMP344 would be ~£50mn over the lifespan of their CfDs. If precedent continues and no IAE claims are approved, there is no offsetting cost to consumers – CMP344 is “upside only”.
- If an IAE were to occur, there would be a short-term cost to consumers under the CMP344 solution. But if CMP344 were not approved, generators would increase risk premia as a result of an IAE being approved. Even when accounting for time value of money (the cost is upfront while the CfD benefit accrues later), the benefit of removing additional risk premia more than offsets the cost.
- CMP344 only removes one element of offshore cable outage risk. A significant cost to developers will remain from lost productivity in the event of a cable failure. Hence developers will remain heavily incentivised to construct offshore infrastructure to high standards of reliability. CMP344 will not meaningfully diminish this incentive. The additional risk to generators from exposure to IAE expenses is not a useful market signal.

Background

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Income Adjusting Events

When an offshore windfarm developer builds assets to connect to the transmission network e.g. offshore and onshore substation platforms, subsea export and onshore cabling. Ofgem holds a tender to competitively appoint an Offshore Transmission Owner (OFTO) to ultimately own and run these assets, instead of them simply passing to the relevant Transmission Operator to operate.

OFTOs are awarded a licence that provides an annual allowed revenue starting at asset transfer. This is used to determine a charge for the windfarm for flowing power over the OFTO's assets in exchange for running them, which feeds into each generator's offshore local circuit tariff.

When an OFTO incurs certain costs beyond its control, it may be able to apply to Ofgem to approve an Income Adjusting Event (IAE). IAEs can be force majeure events, amendments to the System Operator Transmission Owner Code, or any other event approved as an IAE by Ofgem.

If Ofgem approves an IAE request, it will grant an adjustment to the OFTO's allowed revenue reflecting the unforeseeable costs incurred. This results in an increase to the offshore local circuit tariff for the relevant generator, adjusted from the start of the next transmission price control period. We are currently in RIIO-ET2, running from 1 April 2021 to 31 March 2026. Any IAEs approved between these dates will be passed through in the next period, speculatively named RIIO-ET3.

No IAE claims have been approved to date. Four claims have been rejected by Ofgem and one is pending a decision. The root cause of claims vary. A recurring example is an issue with subsea cabling that was not, and could not have been, identified by previous inspections, and was therefore not reasonably foreseeable; in such cases, the IAE value reflects the associated repair costs.

Activity prior to this report

CMP344 Clarification of Transmission Licensee Revenue Recovery and the Treatment of Revenue Adjustments in the Charging Methodology is a proposed modification to the Connection & Use of System Code (CUSC) that was raised by RWE in May 2020. It argues that the CUSC is currently not clear on the process for recovering IAE costs and seeks to provide clarification and address a perceived disparity about who pays for the cost of IAEs.

The modification would result in adjustments to OFTO revenue from IAEs being recovered in the long term from all demand users via Transmission Network Use of System (TNUoS) charges, and not solely through the offshore local circuit charges of the affected windfarm. The modification highlights the view that recovering IAE costs from a windfarm imposes a “windfall loss” as it is impacted by cable faults twice: first through lost generation revenue as a result of the outage, then through incurring additional network charges to cover the costs to the OFTO of making repairs.

CMP344 was developed by a workgroup and sent to Ofgem in January 2021 for a decision. The regulator sent the modification back to the workgroup for further development in May 2021, seeking clarity on if the modification would be better progressed under OTNR, which costs the modification applied to and how the legal text would be adjusted to reflect those identified costs, and providing quantitative information about how the change would impact different network users. This has been assigned medium priority by the CUSC Panel and the workgroup reconvened in September 2022.

RWE commissioned this report to progress industry aims by providing quantitative supporting information.

Methodology

Cornwall Insight's approach to this analysis was as follows:

- We reviewed the IAE applications submitted to Ofgem to date to inform potential additional TNUoS costs which would be incurred by generators under current arrangements
- We undertook a high-level review of subsidy bidding strategies (e.g. CfDs) in relation to the treatment of risks beyond a bidder's control
- Taking central, high and low cases for generator assumptions on the likelihood of an IAE impacting their operation, we modelled the impact of IAEs TNUoS risk on CfD costs. This considered how much generator CfD bids (required strike prices) would change if they did not need to take into account the impact of TNUoS costs related to IAEs
- Using NGESO's five-year TNUoS forecast, we identified how changes to charges to be recovered via TNUoS would affect charges for different user types under CMP344 reforms

At the time of this report the number of approved IAEs has been nil. Our analysis assumes that the information contained in the IAE applications will be utilised by generators to illustrate the potential severity and frequency of any future IAEs.

IAE characteristics

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IAE claims to date

We identified five claims for Income Adjusting Events (IAEs) since the OFTO regime was established. In that time, there have been ~200 years of offshore wind operation. Of the IAE claims to date, four applications have been rejected by Ofgem and the other is pending.

Figure 1: Proposed IAEs since beginning of OFTO regime

Windfarm	Decision date	Outage date	Status	Submitted claim value (unadjusted)
<u>Blue Transmission London Array</u>	October 2016	RY 2014-15	Rejected	£1.8mn
<u>Gwynt y Môr</u>	May 2017	March 2015	Rejected	£10.2mn
<u>Thanet</u>	May 2017	February 2015	Rejected	£11.7mn
<u>Gwynt y Môr</u>	June 2020	September 2015	Rejected	£14.2mn
<u>Gwynt y Môr</u>	n/a	October 2020	Pending	Redacted

The claim values have not been adjusted for inflation. Future IAE claims could be expected to be on average higher than those listed here due to inflation. The UK has seen inflation equivalent to 24% (CPI) since the outage in 2014, and the Bank of England forecast rates in 2022 to reach 13% as part of an upward trajectory.

Although four IAE applications were deemed ineligible by Ofgem, the claim cost information is consistent with costs and circumstances for an eligible outage claim. Note Gwynt y Môr's September 2015 claim was initially approved, then subsequently quashed, showing how finely balanced the risk is. Importantly, this is the information that would be available to investors in generation assets for risk modelling purposes.

The mean average of the claims cost is £9.48mn, while the median is £10.95mn. For modelling purposes, the cost of an eligible IAE will be deemed to be £10mn.

IAE Impacts on TNUoS credits

Some TNUoS generation zones have negative wider tariffs, meaning that generators within them receive credits on a £/kW basis. These credits are based on the generator's Transmission Entry Capacity (TEC) adjusted by the average percentage output it achieved over the three settlement periods of highest output that are separated by 10 clear days over the winter period. For example, a generator that achieved 100%, 99% and 98% output in its three highest settlement periods would receive credits based on 99% of its TEC.

A generator will only receive less than 100% of its potential TNUoS credits if it has no more than three 100% output settlement periods in a given winter, whether due to an IAE or other circumstances. An offshore windfarm will typically hit 100% output on 20% of settlement periods over winter, so would expect to receive the full wider TNUoS credit if it were applicable.

Hence, alongside the loss of generation revenue and potential additional TNUoS cost under an IAE, generators may also face additional downside from a loss of TNUoS credits due to an OFTO outage. While it is unlikely an OFTO outage would last the full winter period, it is not unheard of, with the outstanding claim for Gwynt y Môr relating to an outage from October 2020 to March 2021.

The loss of TNUoS credits would not be impacted by CMP344, so it is not considered in the remainder of the analysis, but should be noted as an additional risk generators face in relation to OFTO outages.

Investor risk perception

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Bid price discovery

Developers play an important role in an auction mechanism as it is their investment decisions that drive the bid price discovery and the ultimate auction strike price. Under an auction structure there are two main drivers to bid price discovery:

- Level of competition: If the level of competition in an auction is high, developers will bid more aggressively. This will result in a lower bid price discovery.
- Risk perception: If externally managed risks need to be considered by the developer, they will take a conservative view in order to secure their return. This will result in higher bid price discovery regardless of a competitive auction being in place.

To secure consumer savings, and achieve lower bids, the auction design should de-risk all possible factors. The premium attached to risk perception hasn't always been identified by policymakers.

The right choice for the consumer:

- Will insulate the bidder from the risk when the saving to the consumer from lower bids is higher than the cost of risk mitigation, should the risk crystallise.
- Will not insulate the bidder from the risk when the saving to the consumer from lower bids is lower than the cost of risk mitigation, should the risk crystallise.

To explore these statements and take the appropriate policy decisions it is important to understand economic theory of bidding behaviour, and Weighted Average Cost of Capital (WACC) and its role in bid price discovery and cost to consumers.

Theory of bidding behaviour

Established economic theory and decades of observed investor behaviour tell us that when making an investment if the expected risk is high, then there needs to be a high expected return attached to compensate for such risk whilst still satisfying the investment objectives of the provider of capital. In economic theory, this decision is termed the *risk-return conundrum*.

When the costs of unpredictable or externally managed risks are absorbed by bidders it can give rise to different kinds of bidding behaviour; the two extremes being:

- High bid price discovery by a bidder more focused on conservative risk management and high return on investment (bullish model)
- Low bid price discovery by a bidder more focused on winning a project and not pricing in risks leading to a so-called winner's curse and projects not being built (bearish model)

The latter type of bidding behaviour can be cause for concern as higher levels of contracted projects not being built in the long-term lowers investor appetite, potentially causing setbacks to the achievement of targets.

Recent examples of uncertainty GB generation investors will have navigated include a mooted generation windfall tax¹, and material cost volatility².

¹ Energy UK <https://www.energy-uk.org.uk/publication.html?task=file.download&id=8147>

² Siemens Gamesa reported the average selling price of onshore turbines reached €0.89mn p/MWh in Q3 2022 vs €0.63mn mid 2021 <https://www.reuters.com/business/energy/wind-turbine-maker-siemens-gamesa-lowers-profitability-forecast-further-2022-08-02/> .

The pragmatic bidder

For this report we assume bidding behaviour is adopted that is a direct and rational reflection of the IAE risks a bidder must account for over the lifetime of the plant - the 'pragmatic bidder' (central model).

This type of bidder allocates a premium or buffer to their bid price, albeit pared to the minimum level they can live with (a walk-away bid considering the risk), given the auction context.

It is key for the success of an auction mechanism that the Pragmatic Bidder can lower their risk perception to a feasible extent where they can lower their bid price while adding capacity to the grid.

A study of 23 EU Member states and GB¹ found that most countries identified the risks caused by policy design to have been the most important in setting WACC.

If a policy is built in such a way where unsuitable externally managed risks are assigned to developers (i.e., developers must assess the level of risk they face over the project life cycle) it will drive up the WACC.

Reassigning those risks to the stakeholder most appropriately placed to manage those risks can result in an overall lower cost to the consumer so long as the savings from the lower bid prices outweigh the possible cost to the consumer of accepting or mitigating the risk for an auction participant. This report considers if CMP344 could deliver these consumer savings.

¹ DiaCore (Ecofys, Fraunhofer, Elareon, EPU NTUA, Energy Economics Group, LEI); The impact of risks in renewable energy investments and the role of smart policies, 2016

Impacts on CfD strike prices and consumers

CfD calculation approach

The pragmatic bidder will factor in the risk of additional TNUoS costs from IAEs into a CfD bid. We have quantified that cost by calculating the increase in a hypothetical CfD bid for a large offshore wind generator.

- In reality, different generators will have different approaches to quantifying and reflecting such risks in CfD bids. IAE TNUoS risk is one of many risks faced by CfD generators, so we have approximated the impact by including IAE applications' costs as an additional OPEX cost for generators and included in a Levelised Cost of Energy (LCOE) calculation.
- Generators will have differing bidding strategies which add a layer of complexity to bids over and above the relatively simple Levelised Cost of Energy (LCOE) calculation we have carried out.

Recent history suggests that the risk of IAEs being approved is low, with none having been finalised to date. The approval of one IAE is likely to increase the perceived risk. Because of the high impact an IAE could have on an investment, generators must factor them into bids. We have used three cases to quantify this:

- Low - A bullish model assuming an event occurs every 1 in 250 years. Generators recognise that there have been no IAEs to date (200+ “running years” of offshore wind operation), but that there is still a risk which could be realised in the coming years.
- Central - A model assuming an event occurs every 1 in 50 years. Generators use the IAE applications (whether approved or not) to date to assess the likely frequency of potential IAE-qualifying events. We have derived this figure using the five IAE claims to date and the 200+ OFTO “running years”.
- High - A bearish model would assume an event occurs every 1 in 15 years. Risk averse generators assume a full IAE will fall within their CfD period.

Considering the significant scope for different factors to influence the relative value over time (both positively and negatively), we have assumed the IAE value remains constant over the given period.

Input parameters

We have used an example 1.5GW site in order to show the impact on future assets as the market grows.

CfD strike prices are typically quoted in 2012 equivalent figures to maintain comparability with AR1 in 2014. We have continued this norm in presenting our bid price results, inflated to today's money when calculating the consumer impact. We have used the [BEIS Levelised Cost of Energy \(LCOE\)](#) data to inform our analysis on load factors and asset costs when determining the strike price. This data is from 2020 (in 2018 prices). The table below provides an overview of these input figures.

Figure 2: CfD Strike price forecasting inputs

Element	Input	Source
Hurdle rate	6%	BEIS LCOE analysis
Load factor	57%	BEIS LCOE analysis
Project life (Years)	30	BEIS LCOE analysis
Capital costs – 2011-12 prices (£/kW)	£1,362.06	BEIS LCOE analysis (deflated to 2011-12 prices)
Fixed operational and maintenance costs – 2011-12 prices (£/kW)	£ 83.73	BEIS LCOE analysis (deflated to 2011-12 prices)
Variable operational and maintenance costs – 2011-12 prices (£/MWh)	£ 2.72	BEIS LCOE analysis (deflated to 2011-12 prices)
Negative price forecast periods	5.7%	Cornwall internal analysis
Transmission Loss Multiplier (TLM)	0.9%	CfD AR4 Framework

TNUoS repayment impact

We have presented two bid prices for each of the Central/High/Low scenarios:

- A bid price based on the BEIS LCOE data – labelled “Base”
- Three bid price scenarios, based on the same inputs as the Base scenario, but with the £10mn cost of the IAE spread evenly across the variable O&M costs of the asset for 15 years (High), 50 years (Central), and 250 years (Low) - labelled “IAE TNUoS”

The results of this analysis are shown in the table below.

Figure 3: TNUoS repayment strike price impact analysis

Scenario	Generator Assumption on IAE Frequency	Bid Price (£/MWh, 2011-12 Prices)	
		1.5GW-Base	1.5GW – IAE TNUoS
Central	50 years	£40.93	£40.96
High	15 years	£40.93	£41.01
Low	250 years	£40.93	£40.94

Source: Various, compiled by Cornwall

The additional operational cost associated with the TNUoS element of an IAE means that the bid price required for the 1.5GW asset would need to increase by around 2.86p/MWh when the generator assumes an IAE every 50 years. This increase rises to 9.5p/MWh where an IAE is expected to occur during the 15-year period of the CfD contract, but the increase is only 0.57p/MWh if an IAE is expected every 250 years.

Whilst these are minimal increases of between 0.05% and 0.2%, this could lead to considerable additional costs to consumers if applicable for all offshore wind assets participating in the CfD scheme.

The choices of the marginal generator are particularly important drivers here, due the CfD auction being pay-as-clear. This means all successful generators are uplifted to the same level.

CMP344 Impact if no IAEs occur

We have assessed the potential increase in costs to consumers as a result of the uplift in bid prices which may take place in CfD Allocation Rounds 5, 6 and 7. These three have been selected as AR7 is the latest allocation round in which projects which will contribute to the 50GW of offshore wind by 2030 could be awarded a CfD, assuming annual auctions. We have approximated the pipeline of assets for AR5 and 6 at 7GW and 6.5GW respectively, leaving 10GW required under AR7 to meet the 50GW by 2030 target. We have then determined a cost based on the difference between the base and TNUoS scenarios discussed on the previous page.

Costs are determined not only by how frequently an IAE occurs, but also by the risk perception of the marginal bidder. If the marginal bidder believes an IAE will happen once every 15 years but it actually happens once every 250, the relative savings from introducing CMP344 are greater than if the marginal bidder believes it will happen once every 250 and an IAE actually happens once every 250.

The analysis shows a significant saving via CfD bid prices if CMP344 were introduced and the CfD risk premia were reduced. In the scenario where the marginal generator assumes an IAE will occur every 50 years (our central scenario), ~£50mn is saved; increasing to ~£167mn when the marginal generator assumption is one every 250 years; and decreasing to ~£10mn when the marginal generator assumption is one every 15 years.

Figure 4: CMP344 Impact analysis – AR5/6/7

Scenario	Generator assumption on IAE frequency	Bid Price (£/MWh, 2021-22 Prices)			Cost to Consumer without CMP344			
		Bid Price - No IAE Assumed	Bid Price – IAE Assumed	Bid Price - Difference	Load Factor (%)	AR5/6/7 Capacity (MW)	AR5/6/7 Volume (TWh)	AR4 Cost / CMP344 Net Benefit (£mn, 2021-22 Prices)
Central	1 in 50	48.35	48.38	0.0286	57.00%	23,500	1,760	50.3
High	1 in 15	48.35	48.45	0.0952	57.00%	23,500	1,760	167.6
Low	1 in 250	48.35	48.36	0.0057	57.00%	23,500	1,760	10.1

Source: Various, compiled by Cornwall

Impact of an IAE occurring

If no IAE occurs, CMP344 would result in lower overall costs to consumers as there would be no IAE cost to recover through TNUoS, and the IAE risk premia would be removed from CfD bids.

If an IAE were to be approved today, consumers would be exposed to a short-term cost. However, generators would likely increase their CfD bid risk premia. Our central case is based on an assumption of four IAEs in every 200 years. If an IAE occurred now, the bid risk would conservatively increase to the equivalent of five IAEs in every 200 years, or 1 in 40 (as opposed to 1 in 50 in our central case).

The realisation that IAEs are more than a theoretical risk likely results in a bigger shift in CfD bids, but we have used a shift from 1 in 50 to 1 in 40 to as a conservative estimate.

We calculate that moving to a 1 in 40 assumption drives a 3.57p/MWh increase in CfD bids, compared to 2.86p/MWh under a 1 in 50 assumption. This would be avoided if CMP344 were implemented, which we estimate would result in a £62.9mn cost saving to consumers across AR5/6/7 projects. While CMP344 would result in consumers facing an additional £10mn cost in TNUoS in the year following approval of the IAE, CMP344 still results in a £52.9mn net benefit to consumers in this scenario.

Therefore:

- The benefit of CMP344 is clear in a scenario in which no IAEs occur – consumers face no cost and save on CfD risk premia
- The benefit of CMP344 actually **increases** on a simple net basis when an IAE occurs – the increase in future generator risk premia more than offset the cost faced by consumers in TNUoS
- However, this does not take into account time value of money. The cost to consumers is in year one while the benefit only accrues once future CfD plant which has factored in increased risk premia due the occurrence of that IAE is operational. This is considered further on the following slide

Impact per customer

If a £10mn IAE were to be approved now, consumers would face an additional £10mn TNUoS cost in 2023-24. Without CMP344, that cost would effectively be “paid back” to consumers by the generator over the RIIO-ET3 period.

After a sustained period of low inflation, the UK has seen rising rates in 2022, driven by historically high energy bills. If customers bear costs in the near term, and recover the value in the long-term the time value of money must be considered, and how that represents value for money for the consumer.

If CMP344 was adopted, the current uplift to CfD generator risk premia would be removed, resulting in a long-term benefit to consumers.

Based on a discounted analysis of the customer cost and later benefit, we have identified that:

- Under our central scenario, if no IAEs are approved, CMP344 being implemented has a net present value benefit of £0.22 per domestic customer
- If an IAE were to be approved, CMP344 being implemented would have a £0.16 net present value benefit per domestic customer, comprising a £0.13 cost in 2023-24 offset by £0.27 per customer lower CfD levies across the late 2020s and 2030s as AR5/6/7 projects come online

CMP344 Impact Summary

If an IAE were to occur under CMP344, consumers would pay more in the short term. But the counterfactual without CMP344 would see generator risk premia increase as generators would perceive an increased IAE risk. So, in the long-run consumers would still be detrimentally impacted.

	No IAE	An IAE occurs
CMP344 adopted	<p>Ideal outcome – no consumer cost in TNUoS or CfDs</p> <ul style="list-style-type: none"> • No recovery required • Future CfD risk premia related to IAEs removed • Consumers benefit overall 	<p>Good outcome – consumers face upfront cost of IAE but no reactive increase in future CfD costs</p> <ul style="list-style-type: none"> • Permitted costs recovered from all demand users via TNUoS, consumers pay more short term... • ...but CfD IAE related risk premia remain zero Consumers benefit overall
CMP344 rejected	<p>Poor outcome – consumers fund risk premia in bids despite no cost ever being incurred</p> <ul style="list-style-type: none"> • No recovery required • Consumers continue to fund CfD risk premia • Consumer detriment overall 	<p>Poor outcome – customers still exposed to upfront costs (albeit paid back in RII0-3) as well as to reactive increase in CfD risk premia</p> <ul style="list-style-type: none"> • Permitted costs recovered from Generator • Consumers save in short term... • ...but CfD risk premia increase based on higher perceived IAE risk Consumer detriment overall

Source: Various, compiled by Cornwall Insight

Impacts on TNUoS

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CMP344 impact on TNUoS costs

To estimate the impact of CMP344 on consumers we modelled how a £10mn IAE would affect TNUoS. We based our assessment on NGESO's five-year TNUoS forecast, including the number of sites in each user category and their assumed consumption volumes.

Our analysis indicates that a £10mn IAE in 2022-23 would result in

- 13p increase per year in TNUoS costs for each domestic consumer
- The per site impact escalating through customer voltage bands, peaking around £10,589
- Over a third of IAE costs would fall on domestic customers, and two thirds would fall on low-voltage users

Figure 5: CMP344 impact on TNUoS demand segments (£)

Overall impact (£mn)	2023-24
Domestic	3.64
Dx LV	3.02
Dx HV	2.04
Dx EHV	1.02
Tx	0.18
Unmetered	0.10

Figure 6: CMP344 impact on per site TNUoS demand charges (£)

£/site	2023-24
Domestic	0.13
LV_NoMIC_1	0.05
LV_NoMIC_2	0.29
LV_NoMIC_3	0.72
LV_NoMIC_4	2.27
LV1	3.63
LV2	6.82
LV3	11.07
LV4	25.15
HV1	16.78
HV2	60.77
HV3	118.74
HV4	305.91
EHV1	190.77
EHV2	738.87
EHV3	1,562.56
EHV4	4,041.21
T-Demand1	462.95
T-Demand2	1,656.79
T-Demand3	3,615.69
T-Demand4	10,588.70