Consultation on Inflexible Offers Licence Condition

InterGen

InterGen are a UK based, independent generator who have developed and operated flexible gas assets for the last 25 years. InterGen's plants generate enough power to supply three million homes, representing around 5% of the UK's electricity demand. InterGen is a world class developer of energy assets with a 3GW pipeline of battery projects at the heart of the company's plan to help decarbonise the GB energy mix and enhance system operability.

Summary

In short, InterGen do not support this licence condition as it would effectively prohibit scarcity pricing. Scarcity pricing, and the ability of flexible generators to be rewarded for delivering during times of scarcity, is a cornerstone of an efficient market and important in creating signals for investment.

Rather than imposing this licence condition, InterGen supports the drafting proposed under the High Balancing Costs Call for Input of November 2022.[1] This is important to avoid a myriad of unintended consequences. In addition, detailed, clear guidance must be delivered on how 'excessive benefit' will be defined, as well as 'reasonable profit' as the guidance provided is vague.

Introduction

InterGen are supportive of the licence condition suggested in Ofgem's Call for Input into High Balancing Costs. This change targeted a specific behaviour, identified as a 'sharp practice': a within day Physical Notification ("PN") revision to zero, designed to take advantage of a plant's physical characteristics, to earn high balancing awards for a longer period than the system requires. This subsequent consultation does not target a specific practise. It effects all generation that submits a zero PN, regardless of when it is submitted.

As submitting a zero PN is normal market practise in effect this acts as a cap on all bid offer prices and therefore effects all participants in the balancing market. This is no longer a targeted condition aimed at a specific practise but a broad rule change which will have far reaching consequences on the whole market.

InterGen believes a full impact assessment of this licence condition change should be considered consistent with that carried out in the Call for Input. This licence change risks dampening price signals and removing scarcity from the market and could lead to an investment hiatus in the battery storage space.

The business case today for new battery storage assets relies on price spreads for capturing arbitrage. These spreads are reliant upon the price volatility, up and down, present in an efficient market that fully reflects the fundamental supply/demand mix. All non-subsidised generators rely on scarcity

[1] Call for Input on options to address high balancing costs, https://www.ofgem.gov.uk/cy/publications/call-input-options-address-high-balancing-costs, (accessed March 2023)

pricing to maintain prices above their long run marginal cost and to keep their generation on the grid to the benefit of the security of supply.

It is likely that government subsidy would be required to cover off this loss of scarcity rent, in the form of increased capacity market awards which could be forced above the cap of £75/kW to keep assets operational and bring forward new build technologies. This code change will cause negative consequences to all three facets of the energy trilemma:

- Security of Supply
- Decarbonisation
- Cost to the Consumer

Scarcity Pricing

It is important to retain scarcity pricing, as it is a key feature of energy market arrangements. It provides market signals in the form of higher prices when the system is tight and in providing security of supply with these prices directing interconnector flows and incentivising generation.

Ofgem approved Balancing and Settlement Code modification P305 in 2015 with the stated aim of sharpening price signals in times of scarcity, on the basis that existing market defects, "could increase the cost of ensuring security of supply to consumers because it could lead to inefficient balancing and dampen incentives for the market to provide flexibility". Indeed, Ofgem estimated consumer savings of £200m-300m by 2030 by implementing P305.

Cash out reform has been successful in bringing additional liquidity to the intraday market from non-physical participants and increasing the incentive for participants to deliver when the system is short. The non-physical traders are attracted to the market by the volatility in an efficient market with scarcity pricing and could exit if volatility is dampened via this proposed intervention.

Should the risk of high prices in periods of scarcity be removed then the forward price for electricity will fall. This drop in available wholesale revenues will cause generators to seek revenues elsewhere and could see costs pushed into other areas such as the reserve markets or the capacity market in the longer run. As such, there is no benefit to the consumer of this approach as the costs to the Electricity System Operator (ESO) taken out of the balancing market will appear elsewhere.

High Balancing Costs

InterGen believe that the high balancing costs being experienced are a reflection on a highly constrained network with insufficient on-demand flexible capacity, resulting in tight margins. To conclude that high balancing costs are simply due to higher offer prices is too simplistic and does not consider constraints across the whole system.

Scarcity pricing has a role in a well-functioning market. The costs associated with balancing the system during times of scarcity do impact consumer bills but only to a very small degree (forming 1-2% of consumers' electricity bills)[2] and avoid loss of load for the consumer. This is in comparison to

[2] Call for Input on options to address high balancing costs, https://www.ofgem.gov.uk/publications/call-input-options-address-high-balancing-costs

commodity prices in the wholesale markets which have seen recent volatility due to geopolitical factors and general scarcity across Europe that is already dissipating. Prices are now expected to fall.

Frontier Economics conclude in their review into the behaviour in the balancing market over winter 21-22 that they found, “no clear evidence of behaviour inconsistent with the market rules” and add that the rules do not place any restriction on the level of bid and offer prices.[3] Frontier Economics add that, “rational behaviour in a pay as bid market would entail:

- Participants increasing offers up to their expectations of the marginal accepted offer
- In periods of scarcity, participants increasing offers potentially to Value of Lost Load (VoLL)

VOLL is currently set at £6000/MWh to maintain a security standard or Loss of Load Expectation (LOLE) of 3 hours per annum. As Frontier state in their review, it is rational and within the rules to increase prices up to VOLL in periods of scarcity.

Balancing costs are set to decrease in the future as electricity storage build ramps up over the next few years and competition in the balancing market puts downward pressure on prices. The short-term high balancing prices will be corrected by these moves in the medium term.

By rejecting the proposed Balancing Reserve service,[4] Ofgem have prevented National Grid ESO from being able to procure significant volumes of operating reserve at the day-ahead stage. Via this service, Grid would be able to procure without the scarcity premiums that can manifest on the day in the Balancing Mechanism (“BM”) when the ESO has fewer options available. This will result in higher balancing costs for the consumer.

Proposed License Condition

InterGen believe the license condition in this consultation goes too far and is not consistent with addressing the behaviour identified in the Call for Input of November 2022. It will cause unintended consequences. The wording of the license condition in the IOLC (Inflexible Offers Licence Condition) consultation is as follows:

“Where a generator has submitted to the ESO a 0MW PN….. (they) will be prohibited from gaining excessive benefit from revenues received in the BM….. (and) generators’ BM offer prices must reflect only their costs plus a reasonable profit that is not excessive.”

Generators can be in the BM for several reasons, including to manage operational risk across a portfolio. Should a Balancing Mechanism Unit (BMU) not forward contract its capacity or buy it back at day ahead, this will result in the submission of a zero PN and will therefore be in scope of this license condition. In this case several considerations go into the setting of the price in the BM as follows:

- The plant should be able to recover at least equal profit to what could have been achieved from selling day ahead. The day ahead delivery could be at maximum capacity for 6-24 hours so the price per MWh in the BM is higher due to lower delivery volume.

[3] Balancing Market Review, https://www.nationalgrideso.com/research-publications/eso-balancing-market-review-2022

[4] Decision to reject an amendment to the Terms and Conditions related to Balancing in relation to proposed Balancing Reserve Service, https://www.ofgem.gov.uk/publications/decision-reject-amendment-terms-and-conditions-related-balancing-relation-proposed-balancing-reserve-service

- Many of the gas plants on the system now run for limited hours of the year for a variety of factors including age (requiring running hours to be managed), efficiency and cost. This means for the limited hours these plants run in a year they are required to make their revenues for the full year to cover their long run marginal cost. Scarcity events are few and far between (Loss Of Load Expectation, or "LOLE", is set at 3) so it follows that there will be high prices during scarcity.

- Volatility in prices is incentivising build out of large volumes of storage assets as seen in the results of the recent T-4 Capacity Auction that saw 5GW of nameplate capacity win 15-year agreements. These assets prequalified and bid into the auction ahead of this licence condition that could fundamentally alter their investment case.

These price drivers should be considered when defining what "excessive benefit" is in addition to the tests proposed. The definition of excessive benefit in the Guidance Document is open to interpretation.[5] When subsequently clarified, it could be overly prohibitive or remains open ended and therefore will cause uncertainty, be open to interpretation and be ineffective as a result. If prohibitive, the licence will push generation out of the BM and into the DA market. This will have significant impact on price signals as most generators would switch to selling Day Ahead as the BM would cease to offer equivalent value. This would act as a volatility dampener, key to storage assets, and cause a reduction to intraday market liquidity.

Impact on Low Carbon Flex Pipeline

The consultation notes that it expects the revision of license condition could incentivise investment in storage assets as it does not target generation with an MZT of less than 60 minutes. InterGen believes this is a misconception. Restrictions within the balancing market will lead to generation being pushed into the DA market and with no scarcity pricing permitted in the BM, this will have the knock-on effect of reducing the spreads that batteries can capture. This materially damages the investment case for batteries which are seen as a key transition technology in the net zero pathway. There are several reasons for this:

- According to Aurora (Feb 23), 2hr duration batteries require a CM (Capacity Market) award of £30-40/kW to support their investment case at a de-rating of 23.6%.[6] This de-rating is set to continue to increase as potential stress events get longer as batteries cannibalise peaks

- Timera (Oct 22) produced some modelling that batteries have a long run marginal cost of 90-100 £/kW/yr and that revenues are likely to fall to ~ 100£/kW/yr by 25/26 as market tightness eases[7]

- 5GW of batteries came through the most recent capacity market with 32.1GW in pipeline according to renewable UK[8]

The prevailing market design is investable for battery storage even with little support required from government/consumer (the capacity market award required to build after taking the de-rating into

[5] IOLC Draft Guidance: https://www.ofgem.gov.uk/publications/consultation-inflexible-offers-licence-condition
[6] Mind the Cap: GB Capacity Market 2026/27 T-4 and 2023/24 T-1 forecast, access on request (auroraer.com)
[7] Timera battery report, Access on request (timera-energy.com)
[8] Pipeline of UK energy storage projects doubles within 12 months, https://www.renewableuk.com/news/601862/Pipeline-of-UK-energy-storage-projects-doubles-within-12-months.html

consideration is in the £7-10/kW range).[9] This is a market functioning well to drive investment. Low carbon, flexible generation has been incentivised onto the system due to price spreads from the volatility in scarcity pricing that has been seen in the last couple of years. As this BESS (Battery Energy Storage Systems) capacity starts to deploy (only 1.8GW is currently functional) it will start to reduce the high balancing costs and high price spreads as there will be significant capacity chasing the price spreads, this will start cannibalisation of the spreads and increase competition in the balancing market.

Under the IOLC, the investment case of storage assets is impaired. Price spreads are already expected to be reduced by 2025/26. If spreads are further reduced, it puts the 32.1GW pipeline of BESS at risk. This would be against consumer interest and will jeopardise net zero targets. This could result in the need for government intervention to prop up the investment case of batteries by increasing the CM award to above £75/kW. This would be at a higher cost to the consumer as it awards all generators, not just low carbon. Should the required capacity of BESS not come forward then costly interventions such as the coal contingency contracts of winter 2022 (£220-420m) will be required to preserve security of supply.[10]

InterGen supports the scope of the initial Call for Input; this subsequent IOLC leads to a myriad of unintended consequences.

Conclusion

The proposed IOLC should not be introduced. As drafted, it causes widespread unintended consequences to the current energy market arrangements. Scarcity pricing has a key role to play in providing investment signals and retaining security of supply. The current market arrangements have incentivised the build out of a pipeline of over 30GW of low carbon flexible generators. The IOLC impairs the investment case for BESS and will push costs into other areas such as the capacity market, bringing no benefit to the consumer.

The best option in InterGen's view is to proceed with the previous code change which targeted a specific behaviour. It is vital to preserve the investment case for low carbon flex for the transition to net zero while simultaneously retaining scarcity pricing to protect security of supply.

1) Do you agree with our proposal to remove the 'within the operational day' requirement for submission of 0 MW PNs? Please provide reasons for your answer.

InterGen disagrees with the removal of 'within operational day' as it totally changes the scope of the consultation. With it included, it successfully targets a behaviour in the balancing market which can lead to high balancing costs in periods where there is no scarcity. If it is removed the unintended consequences to the whole energy market will be significant. It will effectively act as a cap on offer prices which would dampen price signals, reduce DA spreads and damage the investment signal for battery storage and other generators that cannot rely on a CFD.

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[9] Mind the Cap: GB Capacity Market 2026/27 T-4 and 2023/24 T-1 forecast, access on request (auroraer.com)
[10] National Grid ESO confirms early detail of winter coal contracts, https://www.nationalgrideso.com/news/national-grid-eso-confirms-early-detail-winter-coal-contracts

As highlighted previously this has an impact on thermal generators whose business models in a world of low load factors (due to high renewable penetration) rely on operating for short periods of time to capture scarcity prices. Without these high price events, generators will cease to remain economically viable, and this will compromise future security of supply with expensive contingency contracts likely to be necessary such as the £220-420m spent by the ESO to keep coal units open for winter 22.

The consultation states that there are equally high balancing costs associated with the submission of 0MW PNs outside of within day submissions and therefore this is a reason to remove 'within operational day'. If the aim of the consultation is to target specific "sharp practice" then this is adequately addressed by including 'within operational day.' If removed, the IOLC effectively prohibits scarcity pricing. The proposed code change would fundamentally change the market, the specificity is lost.

2) Do you agree with our proposal to limit the scope of the condition to generators with an MZT greater than 60 mins? Please provide reasons for your answer.

If a licence condition is to be introduced, it must capture **only** the behaviour that Ofgem seeks to prohibit as otherwise it will result in unintended consequences. As proposed, InterGen do not support any such condition at this stage.

If, however, 'within operational day' is kept in the licence condition, then InterGen accepts the inclusion of limiting the scope of the consultation to generators with a MZT of greater than 60 minutes.

It must be noted however that the consultation uses the rational that storage assets should be exempt from this code change as it is normal practise for this asset class to submit zero PNs and therefore should be excluded. It is also normal practise for thermal assets to submit zero PNs. It is impossible to justify changing the scope of the consultation so that it does not affect the normal operation of storage assets if it affects the normal operation of another generation technology (CCGTs). A level playing field must be maintained for true and fair competition across technology types.

In addition to this InterGen were looking forward to participating in the Balancing Reserve service proposed by National Grid. This was seen as a proactive move by ESO to procure low-cost balancing reserve day ahead. InterGen also notes the reason for this was that it did not comply with Article 6 of the ER. To be specific:

"1. Balancing markets, including prequalification processes, shall be organised in such a way as to:

(a) ensure effective non-discrimination between market participants taking account of the different technical needs of the electricity system and the different technical capabilities of generation sources, energy storage and demand response"

In InterGen's view this license condition discriminates against plants with a MZT of over 60 minutes so using the same rationale this license condition should not come into force.

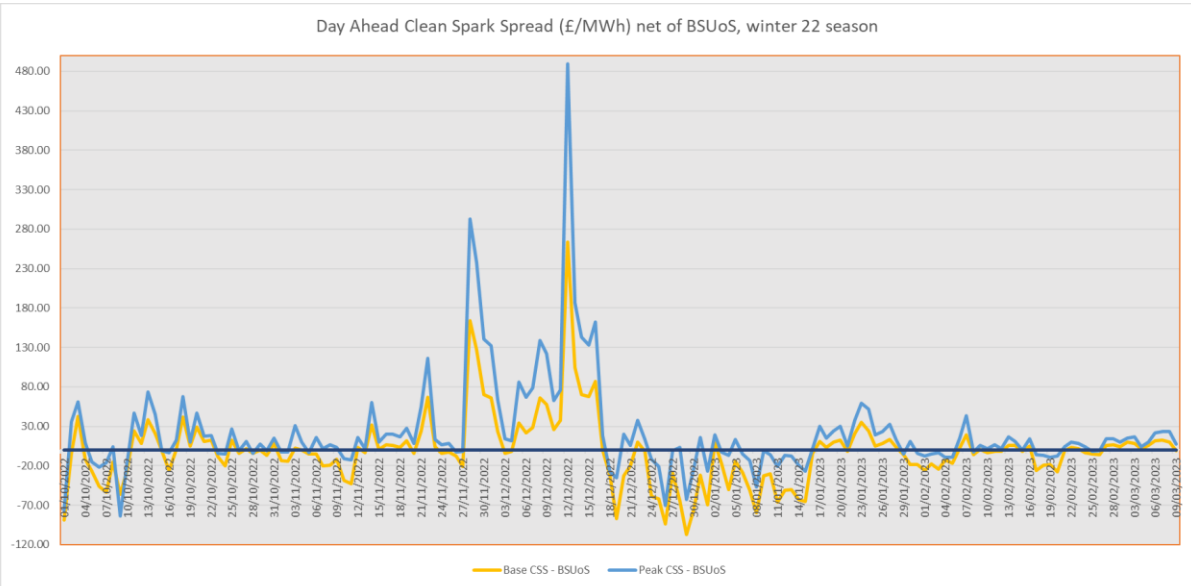
3) Is the proposed licence condition drafting in Appendix 1 sufficiently clear? Are there any drafting edits or additions that you would encourage us to consider?

InterGen are not in favour of the license condition. The licence condition should not apply if the offer is not accepted. Guidance from ESO and Ofgem is to use pricing (not technical parameters) to signal that they do not wish to dispatch. Under this licence condition it may be difficult to prove that a generator did not seek excessive benefit even if it does not run in the BM. There should be another way for BM Units to indicate they do not want to run, other than submitting highly priced offers.

The paragraphs on a 'flexible path' and 'inflexible path' require further explanation and do not seem to add anything, except confusion.

4) Do you agree with our approach to considering excessive benefits, as set out in the draft guidance? Are there any other factors we need to consider for inclusion in the supporting guidance?

InterGen do not think that the guidance is sufficiently clear and places the burden of interpretation with the generators. One possibility would be for Ofgem to compile a catalogue of case studies defining what excessive benefit is in certain scenarios. InterGen sees issues with the description of reasonable profits in line with "the offer price in the settlement period under consideration to allow for reasonable profit to be earned, commensurate with a level of profitability that is in line with an average for the GB electricity generation sector." Each generating unit in the GB market will be operating on different business models with varying long and short run marginal costs. It is unfair to determine what is excessive based on an average especially when considering that plants with the highest running costs are the most likely to only be operating in very few settlement periods during which they must earn enough revenue to remain viable for the rest of the year. An average, by its definition, will not accurately reflect scarcity prices which will always be outliers under this measure.



The above chart illustrates the Day Ahead Clean Spark Spread in MWh net of BSUoS for winter 22 (01 Oct 22 to 09 Mar 23). The average baseload spread for the winter to date is -£1.49/MWh and for peaks it is £22.50/MWh. These prices have delivered under the current market regime against a backdrop of very high commodity prices caused by geopolitical issues. Stripping out the three-week period of scarcity that occurred 27/11-16/12 then the average drops to -£10.98/MWh for baseload and £6.83/MWh for peak delivery.

Without the high prices caused by scarcity, CCGTs would have been uneconomical throughout the winter period where typically they need to make their returns to sustain operations through lower priced summer periods. As the system transitions towards net zero gas generation is depended upon to deliver during tight margin days. Without the scarcity pricing of the current market arrangements gas generators will need to find alternative revenue streams to remain operational.