

Statutory 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

Key Points

1. InterGen welcome changes made for this statutory consultation with the reinsertion of "within operational day" requirement, but we still believe that there will be unintended consequences as a result of introducing this licence condition.
2. InterGen welcome the clarification on scarcity pricing but query both the factors Ofgem look to consider in pricing considerations in times of scarcity, and also Ofgem's reasoning that the system is purely drive by peak demand.
3. InterGen believes that the guidance doesn't go far enough in defining scarcity pricing, or reasonable profit, and places the burden of interpretation on generators.
4. InterGen believes that the new licence condition should not be seen as a cure for high prices, and that we believe high prices are a sign of a well-functioning market.
5. InterGen urges Ofgem to ensure that the changes are fully considered, due to their wide-ranging nature and potential impact.

InterGen welcome the updates made for this statutory consultation which align closely with the original proposed licence condition changes contained in the Call for Input. The reinsertion of, 'within operational day' will prevent the sharp practice addressed in the initial call for input without restricting PN updates that are carried out under normal course of business. Operators should retain discretion to reschedule plant dispatch, however, in the instance of PNs being reduced to zero at short notice on the operational day, then BM prices that seek excessive benefit should be prohibited as per the IOLC drafting. We also welcome the clarification of Ofgem's view on scarcity pricing.

Through our operations, we have identified various difficulties and oversights within the IOLC guidance. Like for like comparison with other plants is extremely difficult and unreliable and the rationale surrounding profit targets and trading strategies is unclear. The minimum amount that a plant can charge without incurring losses is the Short Run Marginal Cost (SRMC) but the Long Run Marginal Cost (LRMC) also has to be factored in. The LRMC covers things like fixed costs, maintenance, development, cybersecurity and insurance. These aspects have increased in cost dramatically over the last 12 months, by millions of pounds per CCGT asset.

The sharp practices of some operators in the Balancing Market, as identified in the IOLC, need to be addressed. These practices are distinct from scarcity pricing, which is an important component of a well-functioning and efficient market. The balancing costs incurred associated with these sharp practices are dwarfed by those caused by managing network constraints of a highly constrained network with insufficient transport capacity. The new licence condition should not be seen as a cure for high energy prices.

We would urge Ofgem to ensure that changes adopted are carefully considered, due to their wide-ranging nature and potential impact beyond addressing the behaviours of some operators in the market.

The State of the Market

InterGen have been supportive of the licence condition suggested in Ofgem's Call for Input into High Balancing Costs. This change targets a specific behaviour: a within day Physical Notification ("PN") revision to zero combined with BM pricing seeking excessive benefit to earn high balancing awards for a longer period than the system requires.

However, we query Ofgem's reasoning that the system is purely driven by peak demand. Analysis of winter 21/22 and winter 22/23 shows that de-rated margin has a greater positive correlation with wind than demand. This shows that Ofgem's view of scarcity pricing to be inaccurate. Therefore, the derived view from peak demand on when high balancing awards are prudent will be incorrect.

In our view, this consultation does not fully take into account the way that those in industry will view costs, volatility and the effect of extreme risk, the distribution of reward in line with risk, what causes scarcity, and what is standard practice. The consultation lacks many of the points raised by industry which were intended to help inform Ofgem to better introduce the IOLC.

All non-subsidised generators rely on scarcity pricing to maintain capture prices above their long run marginal cost and to keep their generation as a going concern and on the grid to the benefit of the security of supply. The Capacity Market and Cash Out reforms (P305) were carried out to address recognised market defects that dampened scarcity pricing signals and resulted in 'missing money'. Scarcity pricing signals, if artificially dampened via regulatory intervention will reintroduce a market defect and drive operators to seek missing money from elsewhere, likely pricing higher in the Capacity Market auctions to compensate.

This code change will cause negative consequences to all three facets of the energy trilemma:

- Security of Supply
- Decarbonisation
- Cost to the Consumer

Security of Supply

Many CCGTs now run for limited hours of the year for a variety of factors including age (requiring running hours to be managed), thermal efficiency and cost. For the limited hours these plants run in a year they need to make their revenues for the full year to cover their Long Run Marginal Cost. Scarcity events can be few and far between (Loss Of Load Expectation, or "LOLE", is set at a security standard of 3 hours per annum) so it follows that there will be very high prices during scarcity.

Market returns are not evenly spread. Volatility in pricing is a feature of the market, exaggerated by the intermittency of renewable generation. This renewable penetration has moved the UK away from being a demand led system for scarcity and prices.

Returns are not linear, as proven by the fact that 4% of winter costs occur on 0.8% of winter days. With the continued increase in wind penetration causing lower average prices, CCGTs will need to find a greater proportion of their annual returns over shorter time periods, and require the ability to price accordingly to maximise these opportunities to ensure future operations, for reasons of security of supply; without this, plants will close.

Ofgem refer to margin between peak demand and capacity throughout the consultation as the only driver of scarcity. Analysis shows that the UK system margin better correlates with wind availability than demand, so we would disagree with the assumption Ofgem makes on scarcity. As it is being used to drive this condition, it will reduce operators' ability to respond to a rapidly transitioning system.

If operators can't price in scarcity rent for extended periods when the system is tight then there will be lower investment signals; either for upgrades to existing plant or development of new. Additionally, if plants which run sporadically are unable to recoup high value in line with true scarcity, they may be forced to close.

The longer-term impact of plants not being able to seek scarcity rents can be seen through the winter of 22/23 with Coal Contingency contracts costing an estimated £220mn to £420mn for one winter. The lower estimate is in line with NG ESO's costing on IOLC behaviours for the whole of operational year 2021/2022. When adjusted to a MWh value, it would equate to a BM price of £7k/MW for those units to do those runs.

However, accepting the correct view on the longer duration of scarcity will help to encourage development of long duration storage which would then cannibalise these revenues, replacing those plants in an orderly fashion and aiding security of supply over the years to come.

Asset operators will hedge portions of their capacity forwards and manage myriad of financial and operational risks ahead of and during delivery. Ofgem only view price vs SRMC in their view of economics. This view means that operators won't be able to hedge their view of risk in a way that is financially prudent. The additional risk that operators need to carry in their portfolio will encourage them to divest. There is no incentive for maintaining a plant without the ability to appropriately manage trading and cashflow risk. As seen with recent financial failures on the retail and generation side of the market, failing manage trading risk is imprudent can seriously impact security of supply when assets fall out of the market.

We observe that Ofgem primarily refer to Winter 2021/22 throughout; we would like to query why studies of balancing costs for Winter 2022/23 were not referenced. The recent winter shows £199mn lower cost with less of the behaviour that IOLC seeks to rule out. The implication of this is that the proposed condition is already less relevant.

The DA prices observed across this most recent winter more fully priced in the market fundamentals making the 'sharp practice' strategy for within day BM less worthwhile for the majority of participants. The recent winter had a significant proportion of higher balancing cost days due to wind driven constraints rather than high offer prices.

Ofgem state that they don't believe the IOLC to be discriminatory, but by applying it to a subsection of the market then it is discriminatory by definition. Over time, this discrimination could reduce the diversification in the fuel mix, making the system less resilient to a variety of market and weather conditions.

Cost to Consumer

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.

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.

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)¹ and avoid loss of load for the consumer.

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". 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.

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) will appear elsewhere.

This has an impact on thermal generators' business models. In a world of low load factors and high renewable penetration, they rely on operating for short periods of time to capture scarcity prices. Without these high price events, generators will cease to remain economically viable. 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 increased cost to consumers does not solely appear through contingency contracts; by pushing scarcity pricing out of the wholesale market and into capacity markets, Ofgem will move scarcity pricing from 'pay as bid' to 'pay as clear'.

To illustrate this, using Baringa's Lifetime Economic Cost methodology, large CCGTs require in the region of £1.25mn per week to pay back capital outlays. The market does not support this level regularly. The need for the occasional opportunities where profits are above average means that they can remain below this level during other times.

With a greater proportion of that value recouped in the wholesale market then the "missing money problem" that the capacity market seeks to resolve is lower. This enables more generation capable of pricing low, thus reduces total outlay for government. Ofgem fails to consider that reduction in wholesale profit pay-as-bid will increase cost to consumer from pay-as-clear sources.

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.

¹ Call for Input on options to address high balancing costs, <https://www.ofgem.gov.uk/publications/call-input-options-address-high-balancing-costs>

By rejecting the proposed Balancing Reserve service,² 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.

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.

Net Zero

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, which saw 5GW of nameplate capacity win 15-year agreements. However, these assets prequalified and bid into the auction ahead of this licence condition which would fundamentally alter their investment case.

Restrictions within the balancing market will lead to generation being pushed into the DA market. With no scarcity pricing permitted in the BM, this will have the knock-on effect of reducing the spreads that batteries can capture, or wholesale value that other new-build tech can achieve. This materially damages the investment case for batteries, which are a key transition technology in the net zero pathway.

The prevailing market design is investable for battery storage even with little support required from government/consumer. This is a market functioning well to drive investment in Net Zero.

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 battery capacity deploys, it will start to reduce the high balancing costs. There will be significant capacity chasing the price spreads, which 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 battery pipeline 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,

² 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>

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

not just low carbon. Should the required capacity 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.⁴

With CMP 305 in 2015, Ofgem have already acknowledged the need for scarcity pricing. This aimed to reduce costs in the longer run by introducing better scarcity signals and pricing. Scarcity pricing reflects the fact that risk isn't linear. In the 8 years since, wind and battery build out has increased. The mix of increased volatility in prices and government support has given a compelling investment case for these net-zero technologies.

As already argued, the missing money problem is likely to push the lack of scarcity pricing into another market. Price would be increased overall, as all generators would be rewarded with the same value. This is hampering decarbonisation efforts, as the derating factors for CCGTs are much greater than low-carbon technology. Whilst this recognises the vital role of CCGTs in security of supply, it is taking potential funding away from net zero technologies. This would only worsen without further amendments to IOLC.

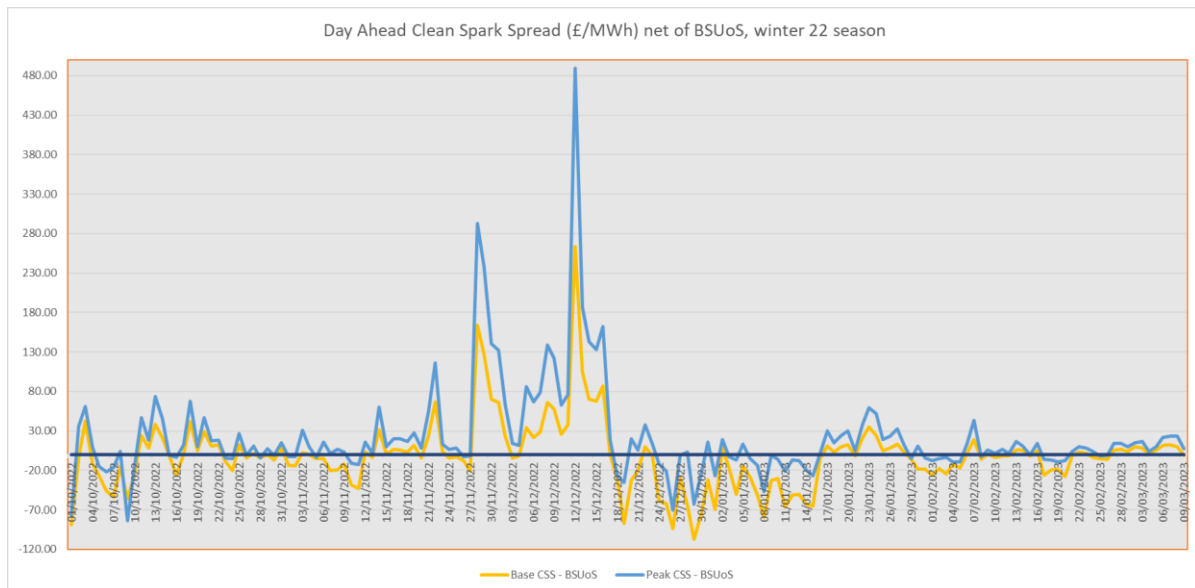
Baringa use Lifetime Economic Cost to model wholesale market and determine plant dispatch regimes and closures. This incorporates fixed costs, variable costs and the cost of capital. In a world of rising interest rates, investors will require a higher return to make the risk in investments more attractive than investing in debt. Limiting scarcity pricing by changing established practices is likely to cause investment flight in the longer term. UK PLC is competing with the Inflation Reduction Act in the US and the Fit for 55 legislation in the EU, so this will impede the UK's efforts to decarbonise and reach Net Zero.

Additionally, Ofgem's view that scarcity only correlates with peak demand reduces the incentives for long-term storage investments which will help achieve net zero targets. We would encourage Ofgem to recognise that the UK's energy system is primarily driven by wind, which is naturally intermittent, so scarcity can occur throughout the day for extended periods. This will allow room for increased prices outside of expected windows, which should encourage long term storage to cannibalise returns and help reduce cost to consumer over the longer term, whilst also improving net zero aims, and security of supply.

Draft 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.

⁴ National Grid ESO confirms early detail of winter coal contracts,
<https://www.nationalgrideso.com/news/national-grid-eso-confirms-early-detail-winter-coal-contracts>



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 in this period 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.

Plants have both a Short Run Marginal Cost (SRMC) which covers running costs only and is the minimum price that a plant charge without operating at a loss. The Long Run Marginal Cost (LRMC) which covers things like maintenance, development, cybersecurity and insurance, which have increased dramatically over recent years. The cost of insurance alone has increased more than 3-fold. All of these costs need to be recovered when the market allows to ensure the plant is sustainable and that this generation capacity is available when the grid needs it.

As part of considering what is reasonable, Ofgem refer to levels which are not significantly greater than had the generator not revised its PN to OMW. This doesn't work to define either reasonable or significantly greater, or factor in the LRMC.

If prices move within day to make running the PN worth zero (against whichever benchmark Ofgem may choose) then we would like to query what constitutes both significantly greater and reasonable profit. This grey area is likely to result in IOLC overreaching and nullifying a standard market practice due to regulatory risk and requiring greater NG ESO actions in the longer term.

Finally, considering the benchmark that may be chosen, if DA pricing is to be assumed then this doesn't reflect how plants hedge and dispatch. The DA price doesn't accurately capture the outcome of risks and changes in intraday. If DA prices were a perfect measure, then there wouldn't be any divergence between DA pricing, SSP and MIDP. However, in times of extreme scarcity these all disconnect to a great degree.