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4 March 2022

Dear Neil,

CONSULTATION ON MEDIUM TERM CHANGES TO THE PRICE CAP METHODOLOGY

We are pleased to respond to your consultation on medium term changes to the price cap methodology. We welcome Ofgem's commitment to make fundamental changes with effect from the next price cap period starting October. It is no exaggeration to say that current market conditions represent an existential threat to many remaining suppliers. Markets are more volatile than ever and prices are set to remain high for longer than expected, heightening volume, backwardation and liquidity risks. Without urgent action to reform the price cap there is significant risk of further supplier exits and associated serious detriment to consumers. Unless the supply sector can return to a more sustainable regulatory model, it will be impossible to attract the new investment, innovation and market entry that will be essential to reaching net zero.

The consultation sets out proposals to change the price cap to reduce risks associated with wholesale market volatility focusing on volume risk and backwardation risk. These changes are considered relative to "a strengthened status quo" which includes the possibility of reviews within the 6 month price cap period in exceptional circumstances. The two main proposals involving structural change are (1) updating the price cap on a quarterly basis; and (2) a 'price cap contract' whereby customers on a default tariff are moved to a 6 or 12 month fixed term price capped tariff.

Alongside whichever of these options is selected, Ofgem is also consulting on reducing the advance notice it gives to suppliers of the updated price cap levels from two months to 28 days; and a new mechanism for managing backwardation costs that are higher than 'normal expectations', with the preferred option being an *ex post* reconciliation that compensates suppliers for costs above a 'normal' dead band (using an RFI to calculate a weighted average of suppliers' costs).

Assessment of options

Structural change to the price cap is essential. A strengthened status quo will not sufficiently reduce the risks of wholesale market volatility. **Of the options proposed, we strongly favour a 12 month price cap contract (PCC)**. We believe that the risks associated with backwardation costs in the future are so significant that any option selected by Ofgem must remove these risks – which the 12 month PCC does but the quarterly cap does not. The absence of exit fees in the PCC promotes customer choice and, in our view, largely neutralises the 'perception of unfairness' that Ofgem refers to. Other benefits of a PCC include:

- it significantly reduces volume risk when prices are rising;
- customers receive a strong prompt to engage every 12 months, which we consider is the optimal frequency to stimulate engagement and avoid engagement fatigue;
- default tariffs will be more easily comparable with the product market which again will facilitate market engagement.

Whilst Ofgem's obligations under s1(6)(d) of the Domestic Gas and Electricity (Tariff Cap) Act 2018 relating to supplier financeability are particularly important here, the positive impact of the PCC on customer engagement is also an important consideration given Ofgem's obligation under s1(6)(c).

Given current market conditions, it is possible there will be a substantial overhang of engaged customers on default tariffs by October 2023, reflecting another 6 months' worth of customers maturing onto SVT and potentially further supplier failures (with customers moving to a SoLR). This overhang of engaged customers on SVT combined with high wholesale prices for next winter could create a 'perfect storm' for volume risk if market prices were to fall sharply in the course of 2023. Although volume risk in a falling market is the main disadvantage of the PCC, it must be recognised that this is not an enduring weakness of PCC, rather it is the consequence of the starting position. Had the PCC been in place over the last 6 months, it is likely that engaged customers would have remained on products and we would not have had this large overhang on default tariffs. We believe it would be wrong to penalise the PCC in the assessment on the basis of these transitional issues when in our view it has clear advantages as a long term solution. Instead, we believe Ofgem should consider complementary measures, such as a much stronger market stabilisation charge (allowing the losing supplier to recover the majority of losses) to mitigate this transitional risk for a limited period.

In our response below, we also propose an **alternative to the quarterly cap referred to as 'H1H2'**, which would be our favoured solution if Ofgem decide not to implement a PCC. This has a number of key advantages including removing the risk of costs associated with backwardation and reducing volume risk. We presented this alternative to Ofgem on 24 February and were pleased to see it raised by Ofgem as an alternative at a supplier workshop on 1 March 2022, with suppliers encouraged to comment on it in their consultation responses. Annex 2 describes the proposal in more detail.

As regards backwardation risks, before Ofgem decides to implement an option which does not directly remove backwardation risk (for example the quarterly cap, or any variation) stakeholders must be given a further opportunity to comment on the detailed design of any mechanism to allow recovery of the costs associated with backwardation. Insufficient detail was given on the ex-post assessment and Ofgem must more clearly explain how it would address the potential flaws of this approach.

Reducing the advance notice to suppliers impacts both suppliers and customers. To enable us to achieve this operationally, we will need to automate many of the processes we currently undertake, but this will be impeded by various prescriptive requirements in the licence. We urge Ofgem to address this with any of the options implemented.

Process going forward

Whilst we welcome Ofgem moving forward quickly with these reforms, suppliers have had limited time to fully assess the ramifications of the various options and many details of the options remain uncertain. We would therefore encourage Ofgem to continue its engagement with suppliers through workshops and bilateral discussions alongside its consideration of consultation responses. This could for example include a further working paper consultation on specific aspects of the proposals ahead of the statutory consultation planned for May. Notwithstanding the urgency of implementing reform, it is vital that Ofgem's proposals are subjected to meaningful scrutiny and challenge from suppliers and the process is fully transparent; we do not believe that the process to date has met this test. It is important that Ofgem commits to a clear set of milestones in relation to this proposed reform, and builds sufficient time into the process for fully engaged and informed consultation, and gives consideration to sharing relevant data with stakeholders.

Other price cap issues

We note that Ofgem has committed to consulting separately on other forward-looking reforms to the price cap, and we consider it is essential these are addressed **in time for the October price cap** given the final stresses now faced by suppliers. Areas which must be addressed include (but are not limited to):

- **Bad debt allowance**: Suppliers' bad debt risk is higher in periods of very high wholesale prices as a result of increased bill value and reduced ability to pay. The current percentage-based bad debt allowance adjusts for changes in bill value but not for ability to pay. Bad debt costs are likely to significant exceed Ofgem's price cap allowance from April 2022 onwards.

- **EBIT margin:** The CMA's rationale for the EBIT margin, which was subsequently adopted by Ofgem, was to allow suppliers to earn a reasonable return on the capital tied up in their businesses. At the time of the CMA investigation, we argued that their estimates of capital employed were significantly too low because they ignored the extent of risk capital required by suppliers to weather market volatility. Ofgem should consider increasing the allowed EBIT margin to reflect increased risks going forward.

- **Shaping and imbalance:** Ofgem's 4 February decision found that shaping and imbalance costs significantly exceeded the allowance in Winter 2021/22. It is vital that this allowance is reformed and updated more dynamically on an ongoing basis.

In view of the sharp increase in risks and costs faced by suppliers as a result of recent market events, we believe Ofgem should urgently consider an interim increase to the level of the price cap between now and October. We are writing separately to Ofgem on this matter.

Finally, we would note that this response focuses on reforms going forward and does not address the question of recovery of excess costs incurred before October 2022 (ie Winter 2021/2022 and Summer 2022), including the potential for a levy arrangement. We reserve our position in relation to these areas.

If you would like to discuss any aspect of our response, please do not hesitate to contact me.

Yours sincerely,

Richard Sweet

Richard Sweet
Head of Regulatory Policy

Annex 1

CONSULTATION ON MEDIUM TERM CHANGES TO THE PRICE CAP METHODOLOGY – SCOTTISHPOWER RESPONSE

Introduction

Ofgem estimates that the price cap to date has delivered around £1bn in consumer benefit each year[1] and driven cost cutting efficiency amongst incumbent suppliers. Wholesale market volatility and the supplier losses and insolvencies resulting from this have, by most calculations, caused at least £3bn consumer disbenefit (cost). The existence of the price cap as well as the ability for poorly managed and/or hedged suppliers to enter the market and gain significant numbers of customers has led to this situation.

An urgent review of the price cap methodology is of critical importance given the dire financial position that all surviving suppliers have been left in as a result of flawed price cap design[2]. Market conditions have exposed problems with the price cap in responding to volatile wholesale markets. Whilst the consumer should be at the forefront of Ofgem's decision making, suppliers should also be able to make reasonable returns and not be expected to run at a loss.

Beyond the timescales that this consultation addresses, Ofgem and Government must go back to first principles to design a mechanism that resolves the current problems and is fit for purpose in a future flexible net zero world. In balancing the needs of consumers, Ofgem must take into account consumers' interest in having a dynamic, competitive and sustainable supply market, which depends critically on supplier financeability.

<u>Aspects of consultation not covered by Ofgem's questions</u>

Before answering Ofgem's consultation questions, we note below comments on aspects of the consultation which are not covered by the questions:

- **Price cap contract observation period**. Ofgem refers (paragraph 4.38) to a 6-8 week observation period for the price cap contract. We consider that a shorter observation would be possible especially if customers are staggered over the different months and believe that in some other areas Ofgem has implied a 4 week observation period, which we think would work.

<u>Chapter 2 – The case for change</u>

1. Are there any other costs and risks to consumers and suppliers that we should consider?

This consultation covers medium term changes to the price cap methodology. Although it focuses largely on the structure of the price cap and the wholesale element, we

[1] Adapting the price cap methodology for resilience in volatile markets, p2
[2] We responded to Ofgem on the significant supplier loss in response to the consultation "Reviewing the potential impact of increased volatility on the default tariff cap: November 2021" on 17 December 2021.

consider that there are other costs to suppliers that are not included in the case for change that should be:

- **Bad debt allowance**: Suppliers' bad debt risk is higher in periods of very high wholesale prices as a result of increased bill value and reduced ability to pay. The current percentage-based bad debt allowance adjusts for changes in bill value but not for ability to pay. Bad debt costs are likely to significant exceed Ofgem's price cap allowance from April 2022 onwards. As part of its reforms to improve resilience in volatile markets Ofgem should also consider how the bad debt allowance could be made more responsive to such events.

- **EBIT margin:** The CMA's rationale for the EBIT margin, which was subsequently adopted by Ofgem, was to allow suppliers to earn a reasonable return on the capital tied up in their businesses. At the time of the CMA investigation, we argued that their estimates of capital employed were significantly too low because they ignored the extent of risk capital required by suppliers to weather market turbulence such as we are currently seeing. As part of its reforms to improve resilience in volatile markets Ofgem should also consider increasing the allowed EBIT margin to reflect increased risks going forward.

We focus above on bad debt costs and the EBIT margin but in previous consultation responses have also mentioned the RO mutualisation costs, gas losses and shaping costs that are not reflected in the current price cap and are an additional source of supplier loss. We understand that Ofgem plans to consult further on some of these elements in 2022 and would encourage it to review and consult on all these elements so they do not fall through the cracks

Chapter 4 – Changes to the price cap methodology

2. To what extent would a price cap contract without exit fees leave suppliers carrying volume risk in a falling prices scenario? How significant would this risk be? How might it be mitigated?

For the price cap contract (PCC), the extent to which there is volume risk in a falling prices scenario depends on how quickly prices are falling. If the fall is gradual, the impact is reduced since the gains from switching are more modest and customers are likely to be some way into their contract before they exit. The losses to suppliers will then depend on how many customers move and how much time they have left on their contracts. Where prices fall suddenly, there is a higher risk to suppliers as the gains from switching will be higher and customers are likely to be at an earlier stage in their contract.

Given current market conditions, it is possible there will be a substantial overhang of engaged customers on default tariffs by October 2022, reflecting another 6 months' worth of customers maturing onto SVT and potentially further supplier failures (with customers moving to a SoLR). This overhang of engaged customers on SVT combined with high wholesale prices for next winter could create a 'perfect storm' for volume risk if market prices were to fall sharply in the course of 2023. Although volume risk in a falling market is the main disadvantage of the PCC, it must be recognised that this is not an enduring weakness of PCC, rather it is the consequence of the starting position. Had the PCC been in place over the last 6 months, it is likely that engaged customers would have remained on products and we would not have had this large overhang on default tariffs. We believe it would be wrong to penalise the PCC in the assessment on the basis of these transitional issues when in our view it has clear advantages as a long term solution. Instead, we believe Ofgem should consider complementary measures, such as a much stronger market stabilisation charge (allowing the losing supplier to recover the majority of losses) to mitigate this transitional risk for a limited period.

We acknowledge that there is a potential challenge in operating a Market Stabilisation Charge (MSC) alongside a PCC regime, since the MSC paid for a customer will depend on which PCC they are on. The gaining supplier will then need to account for this in setting the price for their product offerings. We can see a few options:

a) including an estimate of a weighted average cost of market stabilisation charge in each product offering;

b) ensuring that certain customers, with large market stabilisation charges, are restricted from changing to some of the products.

It is also important that suppliers are not required to allow customers to move between PCCs in different months but only between PCCs and available products. This will mean that engaged consumers can be prevented from gaming the market at suppliers' expense. We recognise that customers could exit to products and then move back to the default after this and do not see an issue with this.

As Ofgem has noted, there might be a perception of unfairness that different customers are on different prices. However, the ability to leave without an exit fee largely neutralises this 'perceived unfairness'; if customers are unhappy with the PCC they are on they can move to a product with their supplier or to a competitor. This is particularly the case in a falling market.

The PCC addresses so many other significant risks, namely backwardation and volume risk on price rises, that we consider that these advantages outweigh the risk relating to the ability to leave without an exit fee, in particular with a much stronger market stabilisation charge in place to cater for sharp price drops.

3. Quarterly updates are a balance between the reduced volume risks and the increase backwardation risks. Please provide evidence and data on the relative costs and benefits of this.

As shown by Ofgem (Figure 4.2 of consultation), backwardation costs would have been even more significant under a quarterly cap than under the status quo. Prices can change but backwardation costs for winter 2022/2023 under 3-2-12 are currently forecast to be 2x worse than under the status quo, due primarily to the large price difference between Q4 22 and Q4 23. Table 1 shows the respective forecast wholesale caps for gas based on prices at 2 March. Due to high price correlation, gas costs are representative of power cost differentials under the two methodologies. We provide a further assessment of future backwardation costs in response to Question 17.

Table 1: Forecast backwardation costs for status quo and quarterly cap based on prices at 2 March close

	Gas					
	Direct Wholesale Energy Cost £/MWh	Direct Wholesale Allowance £/MWh	Difference (Supplier Margin) £/MWh	Seasonal Demand MWhg/ customer	Margin £/ customer	Cumulative Margin £/customer
6-2-12						
Q4 22	125.6	107.5	-18.1	4.0	-71.5	-71.5
Q1 23	125.6	107.5	-18.1	5.0	-91.0	-162.5
3-2-12						
Q4 22	140.1	116.2	-23.9	4.0	-94.6	-94.6
Q1 23	133.5	88.2	-45.3	5.0	-228.3	-322.8

We believe that the risks associated with backwardation costs in the future are so significant for supplier viability that any option that does not remove these risks is not acceptable. For this reason, we strongly object to implementation of a quarterly cap or the retention of the status quo. As explained further below (see our response to Questions 15, 16 and 17), we do not consider the *ex post* adjustment to account for excess levels of backwardation costs is viable, given the high levels of expected costs, the political and other difficulties of amending the price cap in an affordability crisis and the arbitrariness of potential methodologies.

Given our strong preference for a solution that does not include the risk of costs associated with backwardation, we propose a new alternative here which we have called 'H1H2'. For the avoidance of doubt, our preferred option remains the 12 month PCC, but should Ofgem reject that option, we believe the H1H2 alternative better addresses the risks associated with backwardation than other options under consideration. The current and quarterly price cap designs create backwardation risk because Ofgem is seeking to protect consumers from seasonal variation in pricing. The H1H2 alternative is a 6 month price cap based on 6 month forward prices but running January to June and July to December, thereby dampening seasonal variations. However, by matching the length of the forward hedge to the length of the price cap it allows suppliers to align cap costs with revenues, avoiding backwardation risk. Annex 2 describes the features of the proposed H1H2 price cap in more detail and presents some initial analysis.

Quarterly updates reduce the volume risks relative to the 6-monthly updates we have currently. However, volume risk remains both when prices increase and when prices decrease. The reduced volume risk also comes at a cost to customers of increased volatility. This compares unfavourably with the PCC, where reduced volume risk does not come at the expense of increased price volatility. Further, Ofgem notes (paragraph 4.11) that quarterly price caps pass through changes to wholesale prices more quickly than the PCC. The PCC smooths the volatility for customers and passes through the hedged cost that the suppliers have incurred on customers' behalf. It gives customers a stable annual price and protects them from price changes.

4. **Please provide further evidence on the impact of quarterly updates and price cap contracts on households and their finances, and how these could be mitigated.**

We do not agree with Ofgem's assessment (paragraph 4.16 and Figure 4.5) that the 12 month PCC would be more volatile than the status quo – at least in terms of the impact on households and their ability to budget. Fixing the price for 12 months means consumers do not face price changes over that period. It also means that suppliers would only face costs relating to customers on the contract if, as a result of price changes, the cost of energy procured closer to the time of delivery on shaping and imbalance which is a similar risk to that faced for product customers. With the 12 month PCC, each customer will only experience the wholesale prices relevant to the observation period for their start date. But that will protect them from volatility over the course of the year and is better for budgeting.

One price change per year is better for households to manage their finances than the status quo and even more so the quarterly cap.

5. Do you think it is unfair that consumers would sometimes have higher or lower prices depending on the wholesale cost at the time their cohort starts the price cap contract? Do you think over the longer run this would even out?

We can see that there may be a perception of unfairness that consumers would sometimes have higher or lower prices depending on their cohort start date. We believe that the absence of exit fees neutralises many of the concerns that consumers and consumer groups may have in this area, at least in a falling market. Consumers who were very concerned that their price was unfair could leave the price cap to join a competitive tariff.

In a rising market, customers maturing onto a higher default contract than their neighbours are on may also feel aggrieved. However, if the market continues to rise, they may feel less aggrieved in subsequent months as they see their neighbours maturing onto even more expensive default tariffs. Any perception of unfairness will likely affect a subset of customers for a period of a few months and should not be given excessive weight in any overall assessment. Moreover, over the course of time, it would be reasonable to expect any such variations between cohorts to average out.

It is worth noting in this context that consumers already have experience in their daily lives of tariffs and prices changing over time and according to when they enter a contract, for example mortgage, car insurance or mobile phone offers. We also consider that customers may be able to accept any such perceived unfairness as a worthwhile trade-off for lower overall costs.

Finally, we would note that the 12 month PCC option would mean that customers on default tariffs and actively chosen tariffs face similar outcomes, which could be seen as increasing fairness within the overall market.

We are considering commissioning some consumer research into consumer reactions to PCC and will be happy to share the results with Ofgem when available. We would also encourage Ofgem to commission research.

6. What opportunity and impact could each proposal have on consumer engagement? And where there may be negative impacts, please provide options to address these. (Please provide evidence.)

Customers will have the 12 month trigger to move off the PCC. In our experience, the end of fixed term tariff communication process (with a defined deadline) is a more powerful call to action than a SVT tariff change communication, even allowing for differences in customer mix. We support a 12 month PCC over a 6 month option since it provides a smoother price for customers and also reduces the chance of engagement fatigue.

We do not agree with the claim (paragraph 4.21) that the quarterly updates will increase the likelihood that consumers will be prompted to engage. In our view consumers are likely to suffer engagement fatigue from such regular prompting and we consider the 12 month PCC as the option with the highest chance of prompting customers to engage with the market. This view is supported by comments submitted by Catherine Waddams in the University of East Anglia response to the CMA's Supplemental Notice of Remedies:

> "Also, it is important to note that the impact of increasing the number of prompts to action on switching rates is probably non-linear: as the number/frequency of prompts increases the resulting increase in switching rates is likely to decrease. Intuitively it seems plausible that quarterly or six-monthly calls to switch may be viewed as 'junk mail/spam' which, at best, consumers ignore and, at worst, consumers view as a nuisance. As a result, as well as being ineffective, such frequent calls to action might represent a reputational risk to whichever body imposed them. Increased consumer communications prompting consumer action will also involve a direct cost to firms which will need to be recovered from consumers. Nevertheless, an annual prompt to switch seems broadly proportionate."[3]

Table 2: Assessment of impact of the proposals on customer engagement

	Enhanced Status Quo and H1H2	**Quarterly update**	**Price cap contract**
Prompt to engage	Twice a year. Once a year preferable but this is not excessive and customers are accustomed to it	4 times a year, high chance of engagement fatigue in relation to switching	Once a year is the ideal prompt to engage
Ability to compare prices with products	Difficult to compare but two changes a year means it is less confusing	Difficult to compare and the number of changes per year makes this more confusing than the enhanced status quo	Default tariff is closest to products and therefore comparison is easiest
Overall relative likelihood of engagement/switching	Medium	Lowest	Highest

The quarterly cap (and to a lesser extent, the status quo) are more difficult for customers to compare with product prices, which will impact a customer's ability to make an informed decision about the benefits of moving to a product (see Figure 3). Ofgem is required under section 1(6)(c) of the Domestic Gas and Electricity (Tariff Cap) Act 2018 to 'have regard to the need to maintain incentives for domestic customers to switch to different supply contracts'. We consider this is an important factor to consider when assessing the benefits of the quarterly cap option relative to the other options.

3 https://assets.publishing.service.gov.uk/media/5652fc2440f0b674d600004b/University_of_East_Anglia-Centre_for_Competition_Policy_resp_to_supp_remedies_notice.pdf, page 3

Ofgem suggests (paragraph 4.24) that customers may make poor switching decisions if they do not know which version of the PCC they are on. We do not see any difficulty in providing clear naming for such contracts and we do not think the risks are any greater than with existing products.

7. What other operational impacts could a quarterly update or price cap contract have? Please provide data on the costs and benefits.

<u>Costs of customer notification and contact</u>

We have noted above the potential negative impact on consumer engagement of the quarterly updates proposal. We would also flag the potential for significant increases in operational costs for suppliers of this option, with impacts relating to printing and postage, and other operational and resource costs. In particular, with prices being updated four times a year, rather than two, we expect this would likely lead to a doubling of our costs compared to the status quo. We think the costs and impact of the price cap contract option would be the same or lower than the status quo, depending on the evolution of costs over time.

Table 3 shows the indicative impact for each proposal across the various cost categories. Customer contact costs are estimated based on [✂]% of customers contacting our call centre in response to a communication (based on experience to date), a cost of £[✂] per contact, and assuming [✂]m default customers. Other operational and resource costs are not included but may be significant. The same goes for one-off setup costs.

Table 3: Impact of the different proposals on cost (indicative)

Option	**Printing and postage (£m per annum)**	**Customer contact (£m per annum)**	**Total (£m per annum)**
Status Quo	[✂]	[✂]	[✂]
Quarterly Updates	[✂]	[✂]	[✂]
Price Cap Contract	[✂]	[✂]	[✂]

For each of the options, we think there could be operational savings in simplifying the customer communications requirements and removing some of the more prescriptive elements currently in place. We set out more detail of this in response to Question 13, as we consider this simplification to be a prerequisite of moving to a shorter notice period.

After the initial challenge of the transition, assuming communication requirements are simplified, the PCC has fewer operational impacts with prices changing annually for customers and the customer group spread over the year. Annual changes and the reduced volume would be easier for our systems and call centres.

<u>Estimated Annual Costs (alternatively termed as "Personal Projection")</u>

We agree with Ofgem's suggestion that the quarterly updates options would likely add complexity to the calculation of the Personal Projection as on an enduring basis, customers on the Default Tariff would only have certainty of costs for three months but with projections required for 12 months. This could lead to challenges for customers making switching decisions with the additional potential for price changes within the immediate 12 months. In contrast, the Personal Projection for the PCC option would take a similar approach to that used for customers on “active choice” fixed term tariffs, and we consider this will support customers in making an informed choice when considering whether to switch from the price cap option to another tariff.

“Price Protection Window” Requirements (PPW)

For both unilateral variations and at the end of a fixed term tariff, Ofgem currently requires suppliers to provide protection for customers who take action to switch supplier or tariff within 20 working days of the change. As Ofgem knows from its own compliance engagement, this obligation is incredibly complex for a supplier to implement, particularly as it is a retrospective protection requiring knowledge of what a customer is going to do in the future. While we expect most, if not all, of the 19 suppliers Ofgem found to be non-compliant implemented it with the clear intention of being compliant, it is clear from how many subsequently made mistakes that this obligation is particularly complex.

The implementation of Faster Switching removes previous arguments and justification for this requirement, and we consider Ofgem should remove this complex obligation on suppliers. From a consumer perspective, when customers can switch quickly and easily, we think this protection could be seen as disadvantaging well organised consumers who take action in line with the timescales communicated by their supplier.

We consider there is potential for adding even more complexity to this obligation under the proposals to amend the price cap methodology. This applies most notably to the quarterly updates proposal and the strengthened status quo where we consider there is potential for two separate price protection processes to overlap. This is because the obligation for customers switching supplier applies where a customer switching supplier in “reasonable timescales” and taking account of all relevant industry processes (objections, rejections etc), this could extend to the start of the next price cap update and a new price protection process. We are concerned that supplier systems may not be able to cope with this additional complexity.

As we note above, we consider any justified need for this protection for consumers will fall away under faster switching and we ask Ofgem to remove the obligation on suppliers and allow processes to be streamlined and simplified.

Prepayment Customers

While a diminishing pot, there are still a reasonable proportion of prepayment customers with traditional meters. We think there are particular considerations for these customers under Ofgem’s proposals. We set out in our response to Question 13 the potential industry technical constraints that reducing the notice period to 28 days could present for these customers.

In addition, we are aware that there remain limitations on the number of tariff codes available within industry for traditional prepayment meters, which acts as an industry cap on the number of prepayment tariffs that can be “live” at any one time. This is particularly of relevance for the PCC option, and can be overcome by limiting the number of cohorts traditional prepayment customers are spread across.

8. **Are there any challenges in transitioning to quarterly updates or the strengthened status quo? If so, please provide details.**

Effective communication of the changes to customers will be crucial to the success of the reform. Although some options may be simpler to explain than others, we do not see this as an insuperable barrier and it should not influence the choice of option.

We would need to see detail relating to how Ofgem proposes transitioning from the ongoing 6-2-6 hedging for the W22/23 cap to a quarterly cap before being able to comment fully on the challenges of this transition.

9. **What would the impact be if suppliers tried to buy the energy requirements for all their customers on price cap contracts in August (for 12 month contracts) or August and February (for 6 month contracts) of each year? Do stakeholders agree there would be liquidity challenges in the wholesale markets? How damaging would this be? Are there any ways to avoid this issue?**

For the immediate transition, we do not foresee a problem since suppliers are already buying energy for winter 2022 delivery. We also do not see an ongoing problem with the gas market which is highly liquid. However, with power there may be an issue since procuring the vast majority of the annual energy required in a one to two month window could drive up prices due to the procurement volumes required. In addition, purchasing the majority of energy for domestic default customers (accounting for ~20% of GB demand[4]) in one month might then reduce liquidity, on a day to day basis, in the remaining eleven months of the year, to the detriment of the market.

For this reason, we consider Ofgem should progress with the approach to stagger the start with 12 different cohorts.

10. **If we were to implement the price cap contract, how should we implement it - with an immediate start and single cohort on a price cap, or with a staggered start and six or twelve different cohorts?**

As we note in our response to Question 9, we do not think a single cohort all on the same price cap will be possible due to liquidity constraints and the potential impact on wholesale prices if all suppliers were to purchase energy for all default customers in the same period. We do however think that the initial implementation should be for all default customers to move to the same cap level from October, and then customers will be transitioned into different cohorts on a predetermined basis as Ofgem has suggested.

In terms of the number of cohorts, we think there may be operational advantages of having six cohorts rather than twelve, for example with internal processes, managing communications as well as mitigating the impact of change over the festive period. This would however need to be balanced against the increased volume risk.

Ofgem is concerned that there are winter price changes for some over the winter period. This is an issue for all consumers in the quarterly option. For the 12 month price cap option it is also an issue for a subset of customers if the cohorts are staggered

[4] Domestic electricity demand is 36% of total demand (103TWh out of 288TWh) and default customers typically account for slightly over 50% of domestic demand.

over the year. For the 12 month PCC, it is possible to ensure that this does not happen in the way that consumers are transferred to the 12 month PCC as described above.

11. What is a fair and practical way to allocate consumers to different cohorts?

We think the most practical and objective approach to allocating customers to different cohorts would be to use criteria that do not include personal customer characteristics which we consider could increase the perceived “unfairness” suggested by some stakeholders. While we have not reached a conclusion yet on the optimal approach, we think Ofgem’s suggestion within its consultation document to use a date-based approach would appear to be objective and reasonable in our view.

We are continuing to consider potential challenges and other options for allocation of customers across cohorts and would flag the following points to Ofgem at this stage:

- A date-based approach appears particularly relevant to customers who have defaulted from a fixed term tariff to the default tariff
- For customers who have been on a default tariff for a prolonged period, it may be more challenging for suppliers to identify a customer’s start date on the default tariff, particularly where suppliers have migrated customer between different billing systems in the past. However, we still consider it is possible for suppliers to identify a reasonable objective date to use for the purposes of allocating customers between different cohorts. For example, this could be the month of migration to a new billing system.
- There remain limitations on the number of tariff codes available within industry for traditional prepayment meters, which acts as an industry cap on the number of prepayment tariffs that can be “live” at any one time which could limit how many cohorts traditional prepayment customers could be allocated to.

Figure 1: Profile of SP customers over the year (indicative)

[✂]

Figure 1 above shows the approximate distribution of ScottishPower customers over the different months based on start date on SVT. Although not completely uniform, customers are reasonably distributed across the months. From a practical perspective and based on ScottishPower's experience, this element of the transition should not be too challenging for suppliers.

Although we do not believe a perfectly uniform distribution is needed, Ofgem may need to grant suppliers some flexibility in their allocation if the proposed scheme would otherwise result in a very uneven distribution. There may also be merit in providing flexibility so that any peaks do not coincide with tariffs starting in January. Over time, of course, the data will change relating to customers joining and leaving the default tariff.

12. Should we consider any of these variations further? If so, which one(s) and on what basis? (Please provide evidence)

Ofgem has proposed a number of variations across each of the three main proposed options being assessed in this consultation. Our comments on these variations are as follows.

Table 4: Ofgem proposed variations

Variation	**ScottishPower comment**
Strengthen Status Quo	
Six month hedge	This would remove risk of costs associated with backwardation and hence we would support this option over the quarterly cap although there are higher volume risks associated with a 6 month cap
Quarterly Update	
A four month rather than quarterly cap	This would avoid Jan 1 price changes but not remove risk of costs associated with backwardation and hence we do not think this option is viable
Setting the price cap on six month rather than 12 month forward prices	This would improve but not remove risk of costs associated with backwardation and hence we do not think this option is viable
Using a six month observation window	This would increase volume risk and would still include risk of costs associated with backwardation and hence we do not think this option is viable
Updating more volatile non-wholesale costs such as CfD and BSUoS	This would likely be more cost reflective, but any changes should be aligned to prospective reforms to BSUoS.
Price cap contract	
The inclusion of exit fees	Whilst exit fees (if sufficiently cost-reflective) would address the volume risk to suppliers in a falling market, we do not support exit fees. Absence of exit fees addresses some of the perceived unfairness with this option. A much stronger market stabilisation charge is a credible option to mitigate this volume risk.
Setting the price cap on six month forward prices (for the six month option)	We do not agree with the 6 month option but if Ofgem were to implement it, this variation is necessary to avoid the risk of costs associated with backwardation

In addition, ScottishPower has developed an alternative which we call the **H1H2 option**. We presented this alternative to Ofgem on 24 February and were pleased to see it raised by Ofgem as an alternative at a supplier workshop on 1 March 2022, with suppliers encouraged to comment on it in their consultation responses. Annex 2 describes the proposal in more detail. Importantly this option removes the risk of costs associated with backwardation, similar to the status quo with the 6 month hedge and the 6 month PCC with the 6 month hedge. We do not consider that any of the options put forward for a quarterly cap address backwardation and hence are strongly against any of these variations although we recognise that there are some advantages to some of them. **We believe the H1H2 option is superior to quarterly and should be considered further by Ofgem if it decides against the PCC option.**

<u>Chapter 5 – Reducing the notice period to a minimum of 28 days</u>

13. Do you have any evidence or data that supports or challenges our assessment of the benefits this? What are the practical considerations for price changes over winter and Christmas?

<u>Complexity of the current prescriptive customer communications</u>

As we have shared with Ofgem in bilateral engagement, a number of activities that we must undertake within the current two month notification period are due to the prescriptive requirements within Ofgem's advanced notice requirements within SLC 31F.5, notably the requirement to provide the Switching Information on Relevant Contract Change Notices which includes the Cheapest Tariff Messaging (CTM). If Ofgem is to move to a 28 day notice period for suppliers, then it must also remove the prescriptive CTM obligation, and rely on a principles-based approach to prompting engagement from customers consistent with the wider obligations currently in place for communications and engagement.

The above adjustment should be made not only for Relevant Contract Change Notices, but also for Domestic Statement of Renewal Terms, as we consider the reduction in notice of updated default prices will also impact supplier processes for extracting the required information for Domestic Statement of Renewal Terms for tariffs with an end date within a month of the date default price announcement.

In our view Ofgem should consider removing the prescriptive nature of the CTM entirely rather than only for Relevant Contract Change Notices and Domestic Statement of Renewal Terms. While we understand that it acts as a prompt for customers to engage, it can also be confusing to customers under the current prescriptive rules. It provides details of two alternative tariffs, which may have been withdrawn from sale by the time the customer receives the communication, or may not be available as an option on the customer's current payment method. In addition, we consider it to be one of the most time-consuming and complex aspects of producing customer communications, creating complexity and potential for error and creating the need for additional controls and review to ensure customer communications are accurate. We consider the current principles-based obligation to prompt engagement from customers is sufficient and should allow the removal of the prescriptive CTM.

If Ofgem cannot take this action in the timescales required for amendments to the price cap, then it must remove the requirement for Relevant Contract Change Notices and Domestic Statement of Renewal Terms to ensure suppliers are able to produce and review customer communications so they can be provided accurately and in reasonable timescales. Suppliers would still retain the obligation to provide the CTM within other communications that fall under the definition of a Key Prompt Point such as customer bills, if Ofgem retains it as a prescriptive element of encouraging and enabling engagement from customers required within SLC 31F.

Process for issuing email and paper communications

We consider the simplification of customer communication requirements will remove one obstacle to suppliers in communicating quickly with customers after the new price cap level is shared with them. However, it is not the only operational constraint placed on suppliers in issuing communications to customers with particular considerations for both email and letter communications.

- **Notification via email:** We stagger our emails by sending them out over a period of time, usually a week, to reduce impact on the contact centres. In a quarterly cap process, there is no reduction in the volumes of emails ScottishPower is required to send compared to the status quo, and therefore we would need to continue this phased approach resulting in a notice period for some customers that is significantly reduced from our current process (which aims to provide circa 30 days' notice).

  With the implementation of faster switching, we do not consider reduced notice periods create consumer detriment, and as the customer can switch with no exit fee, we do not consider this to be an issue.

  The need to stagger the issuing of emails under the PCC option is reduced significantly due to the lower volumes of customers, which we think will support notices being provided to all customers earlier than in the quarterly updates option.

- **Notification via letter**: In both the quarterly updates and PCC option, the constraints at printers and timescales for printing and postage will lead to less notice being provided to offline customers and we do consider there is potential under the quarterly updates option in particular for some customers to receive their letter very close to the effective date of the change. Similar to the above, we consider the move to faster switching should act to limit any impact of this reduced notification period from historic experience.

Traditional Prepayment Customers

While the process of communicating a price change to prepayment customers will be similar to that for credit customers, we are aware that the operational process for changing the price for traditional prepayment meter customers is more complex than traditional credit meter customers or all smart meter customers due to additional industry bodies involved in the process of updating the new prices to the customer meters.

In particular, suppliers need to involve the PPMIPs and the NSPs to ensure the correct prices are sent to the meters. We understand that the time required by these parties is likely to account for a significant proportion of the notice provided by Ofgem. Added to the time required for suppliers to process the prices once announced by Ofgem and pass to these industry bodies, we consider there is a risk of a delay in prepayment prices being updated on traditional prepayment meters under a shorter notice period. This also limits the opportunity for resolution of any issues experienced and, as is widely recognised, prepayment customers are at greater risk of detriment due to the potential for self-disconnection. Therefore, it is important that all parties have sufficient time to review and ensure processes are accurate.

14. Do you have evidence or data to support a move to a shorter implementation window – such as 14 days? What are the potential risks to consumers of a shorter notice period? And what are the operational considerations?

As we have noted above, there are a number of operational and technical constraints that face suppliers to provide reasonable notice even with a 28 day notice period. We would be very concerned if Ofgem were to move to a 14 day notice period as we consider in a reasonable proportion of cases, customers would receive notification on or after the change had taken effect even where Ofgem makes the changes we have requested to simplify the customer communication process.

For traditional prepayment customers, our understanding is that it would be almost impossible for suppliers to be able to complete the process to pass new prices to the customer's meter due to limitations within industry processes.

We think this would also prompt greater numbers of customers to contact their supplier concerned about a change that had taken place in the past, which would add to supplier costs and resource constraints.

Ofgem must also consider the potential impact on other customer processes, and in particular the requirement to inform customers of their default option within Domestic Statement of Renewal Terms. Reducing the notice period to 14 days would lead to customers also receiving those communications on or after their fixed term tariff has ended.

Chapter 6 – A new mechanism for managing backwardation costs

15. Given the changes in the wholesale market since summer 2021, how should these be reflected in the deadband calculation?

The second half of 2021/22 has confirmed that market conditions and prices are impossible to predict. Whilst the deadband calculation Ofgem used for W21/22 backwardation cost recovery served a purpose, we have concerns about continued use of a calculation based on historical pricing to determine what is "normal". The deadband itself is an ad hoc construct with no theoretical underpinning and the calculation of the threshold is arbitrary. This raises a number of difficulties with the approach:

- Why should the cut-off be one standard deviation rather than 0.9 or 1.1 standard deviations?

- The deadband used for W21/22 costs was based on a single hedging profile (6-2-6) but subtracted from a weighted average based on a mix of hedging profiles; this raises concerns over lack of internal consistency.

- Given the relatively small number of data points since 2019, the estimate of deadband value may change materially as each new data point is added; for example, adding the W21 data point increases the standard deviation from £15.8 to £19.5 per customer (see Table 5 below).

- The standard deviation-based approach relies on the statistics of energy markets remaining constant, which is not necessarily the case.

Table 5: Modelled backwardation costs and contango benefits for a theoretical supplier (£/customer)[5]

	W 18	S 19	W 19	S 20	W 20	S 21	W 21	SD (to S21)	SD (to W21)
Backwardation/ contango	-20.0	12.0	-15.0	16.0	-7.0	13.0	-35.0	15.8	19.5

Given the scale of the backwardation impact currently forecast for W22/23 and beyond (see Table 6) we would need to be assured that any mechanism for backwardation cost recovery will fully reflect the cost suppliers have incurred. We do not have confidence that this can be achieved via a 'deadband' process.

16. Do you have any views on the challenge of collecting backwardation costs from suppliers via RFI?

Setting aside our fundamental concerns about the deadband approach (see our response to Question 15), we think there are two approaches that Ofgem could take to setting a backwardation adjustment:

a) Comparing the weighted average of actual supplier backwardation costs (obtained via RFI) against the deadband.

b) Comparing the calculated backwardation cost for a supplier using a representative hedging profile against the deadband (this would need to be the same hedging profile as used to estimate the deadband).

Although Ofgem used the first approach for W21/22 costs, we believe the second approach would be better going forward. It avoids the internal inconsistency problem identified in our response to Question 15, and it would provide a greater degree of certainty to suppliers as to the adjustment they could expect to receive. Suppliers would still be free to deviate from the default representative profile if they wished, but they may consider that following that hedging profile minimises their risks.

Whichever approach Ofgem adopts, it should make its calculations available to suppliers to scrutinise and challenge if necessary; this may require a 'disclosure room' approach if actual supplier costs are used.

17. Are there additional costs or benefits of taking an ex-post approach in this instance? If so, please provide details or evidence of these.

Due to extreme financial pressures we do not consider the ex post adjustment to account for excess levels of backwardation costs to be viable, given the high levels of expected costs and the political and other difficulties of amending the price cap in an affordability crisis. Table 6 shows forecast backwardation costs based on prices at 2 March 2022. The forecast backwardation cost for winter 2022/2023 is £316 per dual fuel customer, equivalent to over £[✂] for ScottishPower. These costs have been

[5] Values taken from condoc paragraph 2.16; SDs calculated by ScottishPower

rising and are now 8x the equivalent W21/22 level. We accept that the market is particularly volatile at present and that forecasts will change, but worryingly we see no sign of natural cost recovery in the period beyond W22/23.

Table 6: Forecast backwardation cost based on prices at 2 March close (for status quo)

	Power					
	Direct wholesale energy cost £/MWh	*Direct wholesale allowance £/MWh*	*Difference (supplier margin) £/MWh*	*Seasonal demand MWh/ customer*	*Margin £/customer*	*Cumulative Margin £/customer*
W22	360.1	272.7	-87.4	1.75	-153.4	-153.4
S23	158.7	167.5	8.8	1.35	11.9	-141.5
W23	174.3	153.9	-20.4	1.75	-35.8	-177.3
S24	127.2	136.1	8.8	1.35	11.9	-165.5
W24	142.8	129.7	-13.2	1.75	-23.1	-188.5
S25	112.5	106.6	-5.9	1.35	-8.0	-196.5

	Gas					
	Direct wholesale energy cost £/MWh	*Direct wholesale allowance £/MWh*	*Difference (supplier margin) £/MWh*	*Seasonal demand MWh/ customer*	*Margin £/customer*	*Cumulative Margin £/customer*
W22	125.6	107.5	-18.1	9.00	-162.5	-162.5
S23	53.4	55.3	1.9	3.00	5.7	-156.8
W23	55.9	51.7	-4.2	9.00	-37.9	-194.7
S24	39.1	39.9	0.8	3.00	2.5	-192.2
W24	40.2	37.2	-3.1	9.00	-27.6	-219.8
S25	29.1	26.4	-2.7	3.00	-8.1	-228.0

	Dual Fuel Totals	
	Cap Backwardation £/dual fuel customer	*Cumulative Backwardation £/dual fuel customer*
W22	-315.9	-315.9
S23	17.6	-298.3
W23	-73.7	-372.1
S24	14.4	-357.7
W24	-50.7	-408.4
S25	-16.1	-424.5

We do not support recovery of backwardation costs on an *ex post* basis given the longer timescales for recovering cost and uncertainty as to the amount of cost recovered. This level of uncertainty alongside the very significant costs associated with backwardation would reduce investor confidence which has already been affected by the issues associated with the price cap and is necessary to deliver customer benefits and a more effective net zero future. Options such as PCC and H1H2 which eliminate backwardation risk directly are much to be preferred.

Ofgem has not stated exactly how it would make such an assessment and makes various comments in the consultation document that give some cause for concern. For example, it suggests it may make any assessment pre- or post-hedging and also may give consideration to the relative efficiency or lack of efficiency of costs. Prior to seeing the detail of how an ex post assessment would work, we are unable to respond fully to this and urge Ofgem to consult on the detail prior to making a decision. We consider that fairness considerations would arise if Ofgem were to decide on a reform option in circumstances where the ex post assessment had not previously been properly consulted on.

For the avoidance of doubt, we consider that Ofgem **must** take the opportunity to remove the risk of backwardation costs from the price cap methodology.

Annex 2

H1H2 PRICE CAP OPTION

1. Introduction

This annex provides further detail on an alternative to the quarterly cap which we have termed ‘H1H2’. We presented this alternative to Ofgem on 24 February and were pleased to see it raised by Ofgem as an alternative at a supplier workshop on 1 March 2022, with suppliers encouraged to comment on it in their consultation responses. Note that all forecast allowances for future cap periods are based on prices on 14 February and these were presented to Ofgem on 24 February.

Our strong preference for price cap reform is the 12 month PCC option. However, should Ofgem decide that a PCC cannot be implemented, we would have strong preference for H1H2 over the quarterly price cap option. H1H2 has a number of key advantages including removing the risk of costs associated with backwardation and reducing volume risk. It also avoids the increased administrative costs and frequency of price cap changes for customers associated with quarterly and also reduces volume risk relative to the status quo and can further address some volume risk by using non linear indexation.

2. Features of the H1H2 price cap

Key features of H1H2 cap are:

a) A 6-2-6 or 6-1-6 hedging profile, which can be hedged by suppliers with no backwardation risk. A 6-1-6 hedging profile could also be used as proposed by Ofgem in this consultation and this helps mitigate volume risk relative to a 6-2-6 approach by moving indexation slightly closer to delivery

b) Cap periods running January to June (H1) and July to December (H2), largely addressing the seasonality issue for consumers[6]

c) A hedging profile which aligns with the current purchasing for W22/23 under 6-2-6 thereby allowing an easy transition to a new cap to begin cleanly in H1 2023

d) A reasonable frequency (twice a year) of price updates for consumers to avoid engagement fatigue.

The H1H2 cap in its most basic form does not address volume risk as effectively as a quarterly cap. However, the indexation does not need to be uniform and non-uniform indexation that places greater weight on prices closer to delivery can better align the H1H2 cap with product prices bringing this option slightly closer to the quarterly cap in terms of volume risk. Continuing the market stabilisation charge (albeit a much stronger version) would address volume risk when prices are falling significantly.

Further, by splitting each winter and summer season across two cap periods, cap prices should better reflect the impact of market events which tend to be concentrated in a particular season. A 6-2-6 or 6-1-6 approach reduces volume risk versus 6-2-12 or 6-1-12 by being more reflective of relevant market prices.

[6] we recognise that H1 demand is greater than H2 demand but observe that Q4/Q1 and Q2/Q3 price spreads are generally quite flat and actually often price counterintuitively to demand

Table 7: H1H2 delivery and indexation based on 6-2-6

	2022	2023		2024		2025	
	H2	H1	H2	H1	H2	H1	H2
Delivery	Q422	Jan 23-Jun 23	Jul 23-Dec 23	Jan 24-Jun 24	Jul 24-Dec 24	Jan 25-Jun 25	Jul 25-Dec 25
Indexation	Transition*	May 22-Oct 22	Nov 22-Apr 23	May 23-Oct 23	Nov 23-Apr 24	May 24-Oct 24	Nov 24-Apr 25

*This assumes a decision at the end of April 2022

3. Comparison of cap methodologies – historic cap levels

Figure 2 and Table 8 show the £/customer wholesale gas allowances for the status quo (6-2-12), the H1H2 option[7] and the quarterly cap. As would be expected, all options perform similarly in benign market conditions, Q119-S21. However, the H1H2 cap (like quarterly) responds more quickly to price changes when volatility increases. The split of W21/22 "market event" across two H1H2 cap periods means pricing better reflects market events although there is a sharp rise between Q4 2021 and Q1 2022 reflecting the extreme market conditions.

Figure 2: comparison of current, H1H2 no index weight and quarterly cap

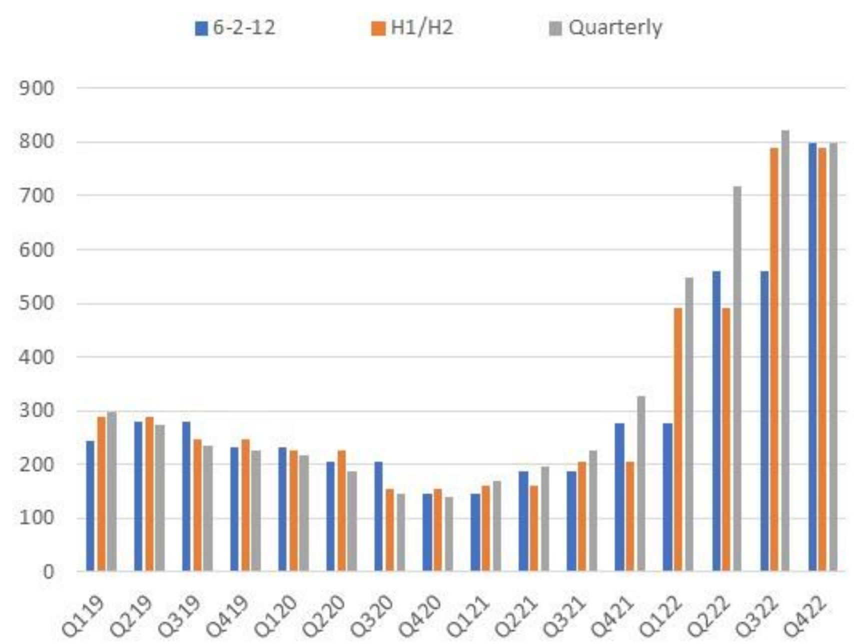


Figure 2 uses wholesale gas allowances as a proxy for electricity allowances due to the lack of availability of historic quarterly data (it is applicable to power due to high price correlation). It also uses Ofgem quarterly and annual consumption figures. £/customer allowances include shaping uplift but exclude the wholesale uplift in the April 2022 cap that is aimed at recovering the unexpected costs from winter 2021/2022. The H1H2 cap here is based on data for the 6-2-6 alternative.

[7] H1H2 modelled based on 6-2-6, but should be similar to 6-1-6

Table 8: £/customer wholesale gas allowances for the status quo (6-2-12), the H1H2 option (the 6-2-6 alternative) and the quarterly cap

	6-2-12	H1H2	Quarterly
Q119	242.9	288.5	298.1
Q219	280.8	288.5	272.5
Q319	280.8	246.8	235.9
Q419	230.5	246.8	224.8
Q120	230.5	226.2	217.6
Q220	206.1	226.2	186.1
Q320	206.1	155.4	146.1
Q420	145.0	155.4	140.6
Q121	145.0	160.5	170.6
Q221	186.8	160.5	194.7
Q321	186.8	205.8	226.0
Q421	276.2	205.8	326.7
Q122	276.2	490.1	548.4
Q222	560.3	490.1	717.1
Q322	560.3	789.9	822.8
Q422	796.7	789.9	796.6

4. Volume risk

The H1H2 cap is less effective than the quarterly cap at addressing volume risk (albeit superior to the quarterly cap in many other respects, such as backwardation). However, even without the proposed index weighting discussed below, the H1H2 cap is better than status quo for the following reasons:

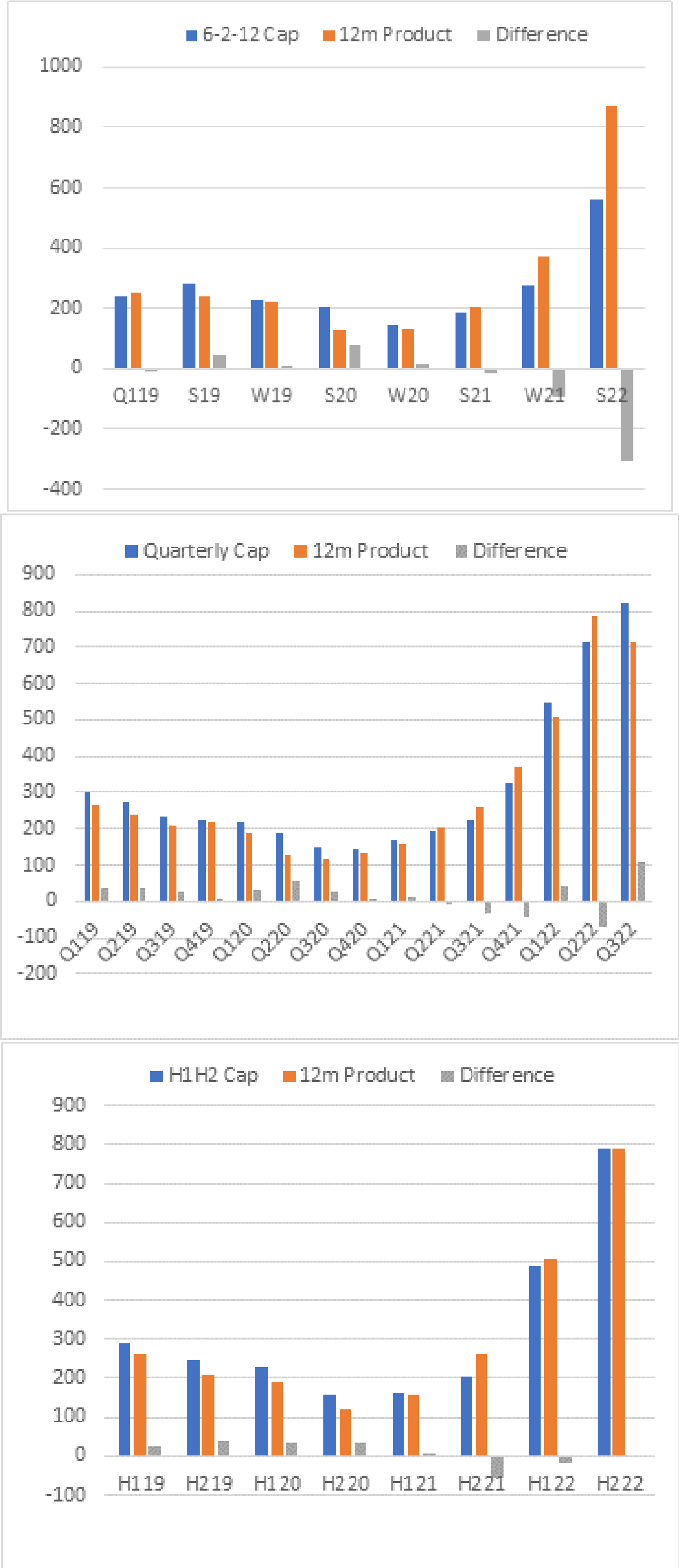
- Removing backwardation risk means the H1H2 cap is more reflective of relevant market prices. At times of price extremes, inclusion of longer dated prices - which are more detached from the fundamentals driving market events - exacerbates price differences between price caps and products and consequently increases volume risk.

- Splitting summer and winter seasons across two cap periods means the H1H2 cap more quickly reflects market events as noted above.

The graphs below in Figure 3 compare wholesale gas caps under H1H2[8], 6-2-12 and quarterly methodologies with the prices that would have set 12 month products at the time when each **respective** cap would have been announced. This analysis is imperfect because price and therefore customer number changes continue to occur after cap levels are announced. However, it does support the idea that a H1H2 cap will better and more quickly reflect market price changes than status quo and by doing so help mitigate volume risk.

[8] H1H2 modelled based on 6-2-6, but should be similar to 6-1-6

Figure 3: Charts to show comparison between current, H1H2 no index weight and quarterly cap with 12 month products in the market



5. Using non uniform indexation to address volume risk

There is a potential to use non-uniform indexation for H1H2 which would give greater weight to prices that are closer to delivery and help better align H1H2 cap prices to the market prices setting supplier products. A variety of profiles could be chosen and Table **9** shows an example of one option for indexation with Table 10 showing the impact on the H1H2 cap profiles. It is also worth noting that indexation could vary between caps if necessary depending on market conditions

Table 9: H1H2 cap with non uniform indexation

H1 Cap		H2 Cap	
Index Month	Weighting	Index Month	Weighting
May	5%	Nov	5%
Jun	10%	Dec	10%
Jul	15%	Jan	15%
Aug	20%	Feb	20%
Sep	25%	Mar	25%
Oct	25%	Apr	25%

Table 10: H1H2 cap impact of non uniform indexation

	6-2-12	Quarterly	H1H2	H1H2 index
Q421	276.2	326.7	205.8	215.6
Q122	276.2	548.4	490.1	568.2
W21	276.2	450.9	365.0	413.1

6. Transition to the H1H2 cap

A transition to the H1H2 cap can make efficient use of ongoing W22/23 hedging activity. Given that Ofgem's decision on wholesale volatility in cap period 7 said that 6-2-6 was the most common hedging approach amongst suppliers, we propose the following option:

- By end of April 2022 suppliers will have hedged 50% of the W22/23 period which is equivalent, in energy terms, to slightly more than 100% of Q422 and so aligns with a H1H2 cap hedging profile.

- Suppliers could convert this winter position into a quarterly position by trading Q4/Q1 spread to achieve a 100% Q422 volume hedge and 0% Q123 hedge. Ofgem could assess the cost/benefit of this activity via RFI or on a modelled basis using, for example, average Q4/Q1 price spreads in Q222.

- From May to October 2022 the H1 2023 (Q1 + Q2) cap would index and fix as per Table 9 above. Suppliers would be able to align hedging with this cap subject to sufficient quarterly liquidity in electricity (also a potential problem with the quarterly cap).

- For Q422, Ofgem could see what the cap would have been based on forward Q322 and Q422 prices from November 2021 to April 2022. There will be a difference between the H1H2 cap level for Q422 and supplier's Q422 energy costs which Ofgem could establish via RFI or model.

- Any difference could be repaid to or recouped from suppliers through a wholesale adjustment to future cap levels.

ScottishPower
March 2022