Decision

Decision on the potential impact of increased wholesale volatility on the default tariff cap

Subject	Details
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We consulted in November 2021 on whether to adjust the default tariff cap (the 'cap') to reflect additional costs facing industry arising from the recent unprecedented rise in wholesale market prices and volatility. In our consultation, we set out a minded to position that the existing methodology of the cap did not fully account for the costs, risks and uncertainties currently facing suppliers. We considered that changing the methodology was in the long-term interests of consumers.

This document sets out our decision to adjust the methodology of the price cap from 1 April 2022 (cap period eight) for costs arising from increased wholesale market volatility and exceptionally high wholesale energy prices. We have carefully considered all evidence and representations made by all stakeholders, and consider that there is clear evidence that suppliers have incurred material extra costs during winter 2021 (cap period seven). We recognise that market conditions remain volatile. In this decision, we also set out further changes we expect to make to the cap (subject to consultation) to ensure the cap continues to reflect the underlying costs and risks of supplying energy to default customers.

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Executive summary

The default tariff cap ('the cap') protects default tariff customers by limiting the amount they can be charged for their gas and electricity. We set the level of the cap to reflect the typical costs to suppliers of supplying this energy plus a fair margin. The overarching objective of the price cap is to ensure default consumers pay no more than a fair price for their energy. We believe the price cap has and continues to deliver against this objective during normal market conditions. However, it's clear changes are needed to ensure the cap is more robust to market shocks going forward. We recognise that industry faced considerable costs during cap period seven, from 1 October 2021 to 31 March 2022, that were not accounted for in the cap, and we must have regard to the need for suppliers to finance their efficient activities.

Our view is that a competitive market where suppliers can recover their efficient costs is in the long-term interests of all consumers. A competitive market ensures suppliers have adequate incentives to become more efficient and provide a better quality of service to their customers. It will also promote innovation and deliver a greater range of products and choices for consumers. It should also ensure consumers do not have to pay for the mutualised cost of supplier failures where efficient suppliers are unable to recover their costs.

The impact of increased wholesale market volatility

The scale and pace of wholesale price increases over recent months represents an unprecedented challenge to the GB energy market. Wholesale prices reached record highs this winter across GB and Europe, market volatility remains well above historical levels, and the pressure this has placed on industry can be clearly seen – 26 suppliers have exited the market since August 2021 through Ofgem's supplier of last resort process and one supplier entered a Special Administration Regime. We fully recognise the significant impact that rising prices will have on all customer bills. We also understand the effect this will have on customers who are in vulnerable circumstances or already struggling with the cost of energy. However, we have carefully considered all stakeholder responses to this consultation and conclude that the efficient costs facing industry during cap period seven were beyond what was accounted for in the price cap.

Accounting for the increased costs of market volatility in the cap

In this document, we set out our decision to amend the Wholesale Additional Risk Allowance,[1] for gas and electricity, to a level that accounts for the increased efficient and material costs incurred by suppliers this winter.

Increased costs incurred during cap period seven

We have concluded that a cap level increase of £59 per dual fuel customer at current Typical Domestic Consumption Value (TDCV)[2] is required to ensure suppliers can recover their efficient costs incurred during cap period seven. The cap uses historic benchmark consumption values rather than TDCV[3] so this figure will be reflected as £61 per customer throughout this document and in the cap model.

This increase is higher than the minded to position set out in our consultation, for two reasons. Firstly, it reflects the magnitude of additional efficient costs facing industry and that the peak of prices and volatility occurred during November and December, after our consultation analysis was conducted. Secondly, it reflects our decision not to include an offset for Contract for Difference (CfD) benefits, on the basis that the majority of suppliers hedge against CfD cost exposure (and so, considering the market as a whole, this benefit was not realised). We set out the breakdown of costs that we have included in the cap level increase below.

[1] As this term is defined in the standard licence conditions of the electricity supply licence and the gas supplier licence, consolidated versions of which are available on this page.
[2]Dual fuel, at Typical Domestic Consumption Value (TDCV) (2,900kWh for single-rate electricity and 12,000kWh gas)
[3] Dual fuel, at the 'benchmark consumption level' value ie the typical consumption values used to set the cap (3,100kWh for single-rate electricity and 12,000kWh for gas). Note that the benchmark consumption value used to set the cap is not the same as TDCV.

Table 1 – Summary of decision, including estimate of costs incurred during cap period seven, which will be recovered during price cap periods eight and nine

Cost	Decision on whether costs have materially departed from efficient costs	November consultation 2021 estimate (minded to position)	Cost impact of decision (£ per customer)
Unexpected Standard Variable Tariff (SVT) demand costs	Yes	£20 to £25	**£41**
Backwardation costs	Yes	£0	**£8**
Shaping and imbalance costs	Yes	£5 to £20	**£12 (electricity only)**
CfD costs	No	-£15 to -£20	**£0**
Total estimate of additional efficient costs	-	£25 to £45	**£61**

Expectation of future uncertain costs

We do not consider that it is in consumers' interests to further increase the level of the price cap from 1 April 2022 to reflect an expectation of future costs beyond those incurred this winter. Doing so would risk consumers paying more from 1 April 2022 for costs where there is still considerable uncertainty whether costs related to wholesale market volatility will materialise, and where other interventions are being implemented to manage these risks. We propose to address future uncertain costs in several ways:

- **financial resilience –** we are today publishing our decision on strengthening milestone assessments and additional reporting requirements in relation to trade sales and certain personnel changes, following statutory consultation in December last year. We are also consulting on changes to Ofgem's guidance on applying for a gas or electricity supply licence.
- **medium term changes to the price cap –** we are today launching a policy consultation on changes to be implemented by October 2022 to include a specific allowance for backwardation costs in excess of historical basis risks, a shortening of the implementation period to reduce volume risks and further consideration of the costs and benefits of a quarterly update and a price cap contract against a strengthened version of the existing six-monthly update.
- **short term interventions -** Ofgem is continuing to consider other short-term interventions that can be put in place to further stabilise the retail market and

protect consumers. This follows our consultation that closed on 17 January 2022. We intend to publish our decision on these matters shortly.

- **consulting on further changes to the price cap in the summer of 2022** – we propose to consult on a suite of further changes to the price cap in summer 2022 to ensure the cap is more robust to market volatility. This package of consultations will include options on the following issues:
  - reform of how the cap accounts for shaping and imbalance costs
  - reform of how the cap accounts for CfD costs
  - aligning with any work being undertaken on the review of supplier financial resilience, if necessary.[4]
- **a further cost review in the summer of 2022 (if appropriate)** – We think the interventions outlined above should mitigate the need for further adjustment to account for uncertain wholesale costs. However, we may conduct a further cost review during the summer of 2022 and will make further changes to the level to the price cap from 1 October 2022 (cap period nine) if it is appropriate to do so.

Together, these reforms represent a substantial package of work to adapt the price cap for suitability to highly volatile market conditions.

[4] We announced our intention to undertake a review in our 15 December 2021 action plan on retail financial resilience

1. Introduction

What is the scope of this decision?

1.0. This document sets out our decision to adjust the price cap methodology in cap periods eight and nine to account for the additional costs incurred by suppliers as a result of rising wholesale market prices and volatility in cap period seven.

1.1. We have decided to make the adjustment by amending the percentage (%) value of the Wholesale Additional Risk Allowance, for gas and electricity, to a level that reflects the efficient and material costs incurred by suppliers during price cap period seven that specifically relate to wholesale market volatility.

Structure of this decision document

1.2. This decision document has the following structure:

- Section 1 sets out the scope of our decision document and its background.
- Section 2 explains our decisions on the key overarching considerations. We have decided to broadly retain the approaches proposed in our November 2021 consultation[5] for this area.
- Section 3 covers our decision surrounding unexpected SVT demand costs.
- Section 4 covers our decision surrounding backwardation costs.
- Section 5 covers our decisions surrounding shaping and imbalance costs.
- Section 6 covers consideration and decisions surrounding Contracts for Difference (CfD) and other costs not explicitly outlined in our November 2021 consultation.

[5] Ofgem (2021), Reviewing the potential impact of increased wholesale volatility on the default tariff cap. https://www.ofgem.gov.uk/publications/price-cap-consultation-potential-impact-increasedwholesale-volatility-default-tariff-cap

- Section 7 sets out a summary of our full package of potential changes to the price cap.

The default tariff cap ('the cap')

The cap

1.3. We introduced the cap on 1 January 2019, which currently protects around 22 million households on standard variable and default tariffs (which we refer to collectively as 'default tariffs'). The cap ensures default tariff customers pay a fair price for the energy they consume, reflecting its underlying costs.

The Domestic Gas and Electricity (Tariff Cap) Act 2018 ('the Act')

1.4. We set the cap with reference to the Act. Section 1(6) states that we must protect existing and future domestic customers who pay standard variable and default rates.[6] The objective of the Act is to protect current and future default tariff customers. In doing so, we must have regard to the following matters:

- the need to create incentives for holders of supply licences to improve their efficiency;
- the need to set the cap at a level that enables holders of supply licences to compete effectively for domestic supply contracts;
- the need to maintain incentives for domestic customers to switch to different domestic supply contracts, and;
- the need to ensure that holders of supply licences who operate efficiently are able to finance activities authorised by the licence.

1.5. The requirement to have regard to the four matters identified in Section 1(6) of the Act does not mean that we must achieve all of these. In setting the cap, our primary consideration is the protection of existing and future consumers who pay standard variable and default rates. In reaching decisions on particular aspects of the cap, the

[6] Domestic Gas and Electricity (Tariff Cap) Act 2018, Section 1(6). http://www.legislation.gov.uk/ukpga/2018/21/section/1/enacted

weight to be given to each of these considerations is a matter of judgment. Often, a balance must be struck between competing considerations.

1.6. In setting the cap, we may not make different provisions for different holders of supply licences.[7] This means that we must set one cap level for all suppliers.

The impact of increased wholesale market volatility

1.7. The scale and pace of wholesale price increases over recent months represents an unprecedented challenge to the GB energy market. Wholesale prices reached record highs this winter across GB and Europe, market volatility remains well above historical levels, and the pressure this has placed on industry can be clearly seen – 26 suppliers have exited the market since August 2021 through Ofgem's supplier of last resort process.

1.8. We also recognise the significant impact that rising prices will have on consumer bills, particularly those in vulnerable circumstances. However, we have carefully considered the evidence provided by industry in response to this consultation and concluded that the efficient costs facing industry in price cap period seven are beyond what is currently accounted for in the price cap.

Decision process

November 2021 consultation

1.9. We published a policy consultation in November 2021, that set out our initial thinking on reviewing the potential impact of increased wholesale market prices and volatility on the cap. Our initial view was that there are likely to be material costs, risks and uncertainties facing suppliers that are not appropriately accounted for within the existing cap methodology due to the increased wholesale prices. If the outcome of the consultation supported the case for an adjustment, our minded to position was to introduce an upward revision to the Wholesale Additional Risk Allowance as an interim solution. Stakeholders provided responses in December 2021. A small number of suppliers provided further evidence on the additional costs faced after the

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[7] Domestic Gas and Electricity (Tariff Cap) Act 2018, Section 2(2). http://www.legislation.gov.uk/ukpga/2018/21/section/2/enacted

consultation deadline. We have where appropriate had given regard to evidence submitted after the deadline, to ensure this decision reflects the best available evidence of additional costs facing industry.

Future process

1.10. We have set out our decision to amend the Wholesale Additional Risk Allowance, for gas and electricity, to a level that accounts for the increased efficient and material costs incurred by suppliers this winter (cap period seven from 1 October 2021 – 31 March 2022). This decision will come into effect from cap period eight, starting 1 April 2022 and will be in effect for 12 months, covering two price cap periods.

Related publications

1.11. The main documents relating to the cap are:

- Domestic Gas and Electricity (Tariff Cap) Act 2018: http://www.legislation.gov.uk/ukpga/2018/21/contents/enacted;
- Default Tariff Cap Decision: https://www.ofgem.gov.uk/publications-and-updates/default-tariff-cap-decision-overview

1.12. The main documents relating to Ofgem's response on increased wholesale market volatility to date are:

- Rising wholesale energy prices and implications for the regulatory framework: https://www.ofgem.gov.uk/publications/rising-wholesale-energy-prices-and-implications-regulatoryframework
- Reviewing the potential impact of increased wholesale volatility on the default tariff cap: November 2021 policy consultation: https://www.ofgem.gov.uk/publications/price-cap-consultation-potential-impact-increased-wholesale-volatility-default-tariff-cap
- Consultation on the process for updating the Default Tariff Cap methodology and setting maximum charges: https://www.ofgem.gov.uk/publications/price-cap-consultation-process-updating-default-tariff-cap-methodology-and-setting-maximum-charges

- Decision on the process for updating the Default Tariff Cap methodology and setting maximum charges: https://www.ofgem.gov.uk/publications/price-cap-decision-process-updating-default-tariff-cap-methodology-and-setting-maximum-charges

- Consultation on Medium Term Changes to the Price Cap Methodology: https://www.ofgem.gov.uk/publications/consultation-medium-term-changes-price-cap-methodology

- Guidance on treatment of reasonable risk management practices in future default tariff cap proposals: https://www.ofgem.gov.uk/publications/price-cap-guidance-treatment-reasonable-risk-management-practices-future-default-tariff-cap-proposals

Your feedback

1.13. We are keen to receive your comments about this report. We'd also like to get your answers to these questions:

1. Do you have any comments about the overall quality of this document?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Are its conclusions balanced?
5. Did it make reasoned recommendations?
6. Any further comments?

Please send any general feedback comments to retailpriceregulation@ofgem.gov.uk

2. Overarching considerations

Section summary

We have decided to adjust the Wholesale Additional Risk Allowance to account for efficient additional costs incurred during cap period seven which are related to increased wholesale market prices and volatility. The adjustment will be recovered over 12 months and equates to £61 on the default tariff cap for a dual fuel customer in cap periods eight and nine.

Additional costs incurred during cap period seven

2.0. We have decided that an adjustment to the cap is required to reflect the efficient and material costs incurred by suppliers during cap period seven that specifically relate to wholesale market volatility. We have decided to make the adjustment by amending the percentage (%) value of the Wholesale Additional Risk Allowance, for gas and electricity.

2.1. This decision will be in effect for cap period eight and nine. From 1 April 2022, the Wholesale Additional Risk Allowance will be set at 8.7% for electricity[8], and 6.1% for gas[9] for price cap period eight. For a dual fuel customer, the Wholesale Additional Risk Allowance equates to £71 for cap period eight. This includes the original value of 1% of the direct fuel cost allowance indexed value for period eight (£10) plus the £61 (£34 for electricity and £27 for gas) that suppliers can recover from default consumers to reflect the additional costs incurred in period seven due to wholesale market volatility.

2.2. The absolute value of the adjustment will be the same for all meter types and payment methods (£61). However, this will mean the % uplift regarding the existing Wholesale Additional Risk Allowance will differ slightly depending on payment method and meter type. We set out more detail on the approach taken in the Appendix 1.

2.3. For period nine, we intend to adopt the same approach. That means the period nine Wholesale Additional Risk Allowance will include 1% of the period nine direct fuel

[8] 8.68% for single-rate metering arrangement and 6.66% for Multi-register metering arrangement
[9] 6.05% for gas non-PPM and 5.89% for gas PPM

cost allowance and a corresponding % uplift for which equates to £61 dual fuel, (£34 for electricity and £27 for gas, as above).

2.4. Considering the market as a whole, we have determined the following cost categories represent a material and systematic departure compared to the allowances provided in price cap period seven under the existing methodology:

- **unexpected Standard Variable Tariff (SVT) demand costs** – costs associated with procuring energy for unexpected and unhedged SVT customers, due to a) an unforeseeable increase in the number of customers moving to SVTs at the end of a fixed-term contract (FTC) expiration, and b) and unforeseeable reduction in the number of customers moving away from SVTs to FTCs.

- **backwardation costs** – backwardation results in a systematic and unrecoverable cost for suppliers beyond the normal basis risk inherent in the cap recovering an annualised energy price in a six-month price cap period. For cap period seven, the costs associated with the market being in backwardation have been outside of the normal expected range.[10]

- **shaping and imbalance costs** – costs associated with forecasting energy demand before refining their positions by converting from less to more granular forward contracts closer to delivery, and the costs of imbalance. For cap period seven, wholesale market volatility has caused electricity shaping and imbalance costs to be materially higher than the price cap methodology had accounted for.

2.5. We set out the breakdown of costs included in the adjustment in Table 2. The considerations in determining each allowance are set out in the following Sections.

[10] Contango is the opposite to backwardation, when the market expects spot prices at the time of delivery to be lower than the current forward price.

Table 2 – Summary of wholesale risk allowance adjustments (costs incurred during cap period seven, recovered during cap periods eight and nine)

	Additional costs - electricity	Additional costs - gas	Additional costs – total
Unexpected SVT demand costs	£18	£23	£41
Backwardation costs	£4	£4	£8
Shaping and imbalance costs (elec only)	£12	£0	£12
Total	£34	£27	£61

Comparability of supplier evidence in consultation

2.6. In recognition of the urgency of the emerging situation and the strain placed on industry, we considered on this occasion it was appropriate to allow industry to have greater than usual flexibility over how they presented the evidence.

2.7. We have considered all evidence provided by industry stakeholders, though we note suppliers have provided a mixture of actual costs and modelled data (where actual data was difficult to provide). We also note that some suppliers provided cost evidence in different formats. For example, some suppliers provided total costs in £million, others in a £ per customer estimate. We have given appropriate consideration to all evidence provided by industry. Not all suppliers provided cost evidence for all (or any) of the cost categories included in our minded to position, and some evidence was provided after the consultation deadline. Where appropriate, we have adjusted the cost evidence to ensure comparability, for example, by converting to the benchmark Typical Domestic Consumption Values (TDCV).

2.8. For transparency, we note that one supplier, which represents a very small proportion of the overall default customer base, has provided a conceptual model which we have not had regard to in this decision. We have reviewed and considered this model, and determined that this model does not represent evidence which may inform the outcome of our decision.[11] The model refers to shaping costs, but the data within does not relate to shaping costs. The model also cannot be used to determine the cost of unexpected SVT demand as it does not include evidence on the numbers of customers, including the number of 'unexpected' or 'unhedged' customers.

2.9. Notwithstanding these evidential issues, as well as the varying quality of the evidence provided, we consider (with the exception of the conceptual model referred to in para 2.8) the evidence submitted from industry stakeholders to be sufficiently comparable and complete to allow Ofgem to reach a robust estimation of the magnitude of additional efficient costs considering the market as a whole. We have made this decision based on the information available to us, in pursuit of our duty to protect default customers under the cap.

2.10. However, for any similar future cost assessments relating to wholesale market volatility, we would intend to issue a Request for Information (RFI) to ensure greater comparability and consistency across suppliers.

Mechanism for allowing costs incurred during cap period seven

Summary of consultation position

2.11. Our minded to position as set out in our November 2021 consultation, was to allow for material and efficient costs by adjusting the Wholesale Additional Risk Allowance. Table 3 below sets out the options considered as part of the consultation process.

[11] For the avoidance of doubt, any further reference to 'supplier evidence' throughout this document does not include the conceptual model referred to in para 2.8.

Table 3 – Summary of price cap amendment options considered

Option	Minded to position	Description of option
Option 1: Amend the wholesale risk allowance	Yes	Revision of the indexed value of the wholesale risk allowance (currently 1% of direct fuel costs).
Option 2: Amend the headroom allowance	No	Revision of the indexed value of the headroom allowance (currently 1.46% of total costs, minus network costs)
Option 3: Implement a bespoke adjustment	No	Implementation of a bespoke adjustment (similar to the COVID-19 adjustment) to account for material and systematic changes in the efficient cost level due to the rising wholesale prices
Option 4: Amend EBIT	No	Revision of the 1.9% Earnings Before Interest & Tax (EBIT) calculated by the CMA to reflect the increased risk facing suppliers through increased uncertainty in wholesale markets.
Option 5: Do nothing	No	No change to cap methodology.

Summary of decision

2.12. We have decided to maintain our minded to position to adjust the Wholesale Additional Risk Allowance. The Wholesale Additional Risk Allowance was specifically included within the cap methodology to account for uncertainty and volatility in wholesale costs, beyond what is already provided for in the other wholesale allowances and headroom. Our view is that, in the current circumstances, wholesale additional risk represents the most appropriate and targeted mechanism to reflect material change in the costs arising from wholesale cost uncertainty and volatility.

2.13. However, having considered the responses to our consultation, we have revised the detail and quantum of our decision. For cap period eight, the Wholesale Additional

Risk Allowance will be set to 8.7% for electricity[12], and 6.1% for gas[13] to reflect the additional efficient costs that were incurred during cap period seven, in addition to the 1% standard allowance. This has historically been set at 1% of the direct fuel cost allowance. As the Wholesale Additional Risk Allowance was specifically designed to account for uncertain wholesale costs, we consider this to be the most appropriate mechanism for adjusting the price cap methodology. The £61 adjustment will be the same for all payment and meter types.

When the decision will have effect

2.14. The adjustment to allow for additional costs incurred during cap period seven will have effect for 12 months from 1 April 2022 (ie in cap periods eight and nine). We consider a 12-month recovery period more appropriate than a six-month period to limit the impact on consumer bills at a time when the cost of energy is already at an unprecedented level.

2.15. Our intention is that the value of the Wholesale Additional Risk Allowance will be updated for the following price cap period (cap period nine) to reflect a new direct fuel allowance, maintaining the same absolute adjustment of £61. This will be subject to any further relevant adjustments, where appropriate.

Summary of stakeholder responses

2.16. Stakeholders who provided views on the mechanism for how we might adjust the methodology to reflect additional costs related to wholesale market volatility were broadly supportive of our minded to position to adjust the Wholesale Additional Risk Allowance.

2.17. One supplier recommends that the Adjustment Allowance mechanism (with float and true-up) should be used in future cap periods where exceptional costs are incurred.

2.18. Two suppliers opposed our minded to position on the basis that the current price cap methodology would not adequately allow them to recover their costs. An alternative from one supplier suggested a mechanism which limits a new entrant/fast growing

[12] 8.68% for single-rate metering arrangement and 6.66% for Multi-register metering arrangement
[13] 6.05% for gas non-PPM and 5.89% for gas PPM

supplier's monthly growth to a fixed percentage for a period of time, as they are not carrying the current costs experienced in this period.

2.19. One supplier noted that the costs associated with wholesale market volatility should be recovered across all customers, and Ofgem should introduce a one-off levy mechanism (similar to how SoLR related costs are recovered) that applies to all domestic consumers. This levy could be added to network charges via the Distribution Use of System Charges (DUoS) or Transmission Network Use of System Charges (TNUoS) that would be passed through the price cap, which the supplier believes would be fairer to both customers and suppliers.

Considerations

2.20. We maintain that our minded to position, as set out in the November 2021 consultation remains the most appropriate mechanism. We note that most stakeholders who provided views on this issue agreed that the additional wholesale risk allowance was an appropriate mechanism to account for these costs.

2.21. We agree that the Adjustment Allowance would be a reasonable approach, which we have considered. We decided not to allow for these costs through the adjustment allowance on the basis that an allowance specifically intended to reflect uncertain wholesale costs already exists within the cap.

2.22. We also do not consider that a levy-based mechanism, which applied to all domestic consumers was the most appropriate mechanism, on this occasion. We carefully considered this proposal and concluded that the practical challenges of introducing such a mechanism would not be feasible to introduce by 1 April 2022, and we did not consider it to be in consumers' or suppliers' interests to unduly delay the recovery of these costs. Additionally, we expect that other reforms to the price cap are likely to reduce these risks on an enduring basis, reducing the need for such a mechanism to be introduced.

Overarching approach to determining level of adjustment

Summary of consultation position

2.23. In our November 2021 consultation, we set out a range of factors to which we may have regard in determining the appropriate level of any adjustment. These factors included a) any surplus that may have accumulated historically within the Wholesale

Additional Risk Allowance, b) any material and systematic reduction of costs to which we may have regard (including CfD costs), and c) the likelihood that indexed allowances will increase considerably from cap period eight and the possibility that indexed allowances will increase beyond the actual costs they were designed to reflect.

Summary of decision

2.24. We have decided not to have regard to any surplus that may have accumulated within the Wholesale Additional Risk Allowance in cap periods one through six. We agree with supplier views on this area that any surplus would be difficult to quantify and conducting a retrospective assessment of this cost allowance alone risks any potential deviations in other cost allowances not being considered.

2.25. We have decided not to have regard to any increases in indexed allowances from 1 April 2022 to offset costs incurred during cap period seven. However, we consider that the increases in the indexed allowances, in some cases, are likely to substantially mitigate the risk of future uncertain costs during cap period eight (discussed further below).

2.26. We have also decided not to have regard to any material departures in the price cap which reflect a material benefit to suppliers during cap period seven. In our minded to position, we set out a view that suppliers were likely to experience a material benefit from CfD related costs being materially lower than the CfD allowance for cap periods six and seven. We note that most suppliers (covering most of the market) have fully hedged their exposure to CfD costs, so did not experience this benefit. We discuss this issue further in Section 6 below.

Summary of stakeholder responses

2.27. We do not provide a detailed summary of stakeholder responses on this area, as this relates to our overarching approach to determining the level of any adjustment. Stakeholder responses on specific cost areas will be captured in the relevant Section of this decision document. Broadly, industry stakeholders did not consider Ofgem should have regard to any surplus that may have accumulated within the Wholesale Additional Risk Allowance for the reason they did not consider that any surplus existed. Most suppliers also noted they did not experience the CfD benefit which Ofgem had posited, on the basis that they fully hedged their CfD cost exposure. The suppliers considered this reflected a prudent approach to risk management which should not be penalised.

Ex-ante allowance of future uncertain costs

Summary of consultation position

2.28. We did not set out explicitly in our minded to position whether we would seek to include an *ex-ante* allowance for the prospect of incurring additional costs related to wholesale market volatility. We did however set out in our minded to position that we would have regard to the risk of setting an adjustment level informed by exceptional market circumstances, and the likelihood that this may lead to overcompensation in future.

Summary of decision

2.29. We have decided not to allow an *ex-ante* allowance for potential future uncertain costs, in addition to the recovery of costs incurred during cap period seven. We do not think it is appropriate to include an *ex-ante* allowance for costs which may or may not be incurred during cap period eight for the following reasons:

- the Wholesale Additional Risk Allowance for cap period eight includes the original 1% value, representing a £10 allowance for cap period eight to allow suppliers to recover uncertain wholesale costs.

- the indexed nature of the shaping and imbalance cost allowance means that, if shaping and imbalance costs during cap period eight are comparable to cap period seven – the increase in the indexed additional direct fuel allowance is likely to ensure suppliers can recover their efficient costs (although it is uncertain if the current exceptional level of volatility will persist in cap period eight).

- we have decided not to offset the ~£5 Wholesale Additional Risk Allowance for cap period seven in determining the level of adjustment required to allow suppliers to recover their unforeseen and unexpected costs during cap period seven. We recognise that this decision represents a prudent assumption in suppliers’ favour, and provides for further uncertain costs during period seven (including transaction costs, costs related to market liquidity or weather risk).

- we recognise the risk that unexpected SVT demand may continue into cap period eight and forecasting SVT demand during volatile wholesale market conditions can lead to additional efficient costs. However, we expect suppliers to respond to the now-known risks of customer demand variance.

- the nature of basis risk in the summer is that suppliers will over-recover, and the level of over recovery is in the normal range so suppliers should not incur material costs related to backwardation. Backwardation costs forecast for period nine are substantial if the market remains at the current level, but we propose to address this through a targeted intervention as part of our consultation on Medium Term Changes to the Price Cap Methodology.[14]

- the headroom allowance will increase by £8, which we consider may provide some additional flexibility to allow for future additional costs.

- the Interim Levy Rate (ILR), which is used to set the CfD allowance for cap period eight will be £0/MWh due to the IRL having a floor of £0. This means suppliers will receive a considerable benefit during cap period eight which is not accounted for in the price cap. We estimate this benefit will amount to ~£7 per customer. We will also be consulting on this issue during summer 2022 to ensure the CfD allowance is reflective of the costs (and benefits) facing suppliers.

2.30. We consider that our decision, considering the factors above, represents a balanced view of providing suppliers with sufficient flexibility to recover uncertain costs without risking consumers paying for costs and risks which may not materialise. This is in line with our duty to protect the interests of consumers protected under the cap.

2.31. However, although we do not consider at this stage that the evidence warrants an *ex-ante* allowance for potential uncertain costs which may be incurred during period eight (and onwards), we will continue to monitor the market and where there are

[14] Ofgem (2022), Consultation on Medium Term Changes to the Price Cap Methodology. https://www.ofgem.gov.uk/publications/consultation-medium-term-changes-price-cap-methodology

grounds to make further adjustments, either upwards or downwards, we are prepared to do so.

2.32. We set out more detail on addition interventions which we are implementing or seeking to implement to reduce the risks and costs of wholesale market variability in the below Sections.

3. Unexpected SVT demand costs

Section summary

We describe stakeholders' responses to our November 2021 consultation on unexpected Standard Variable Tariff (SVT) demand costs. We set out our consideration of these responses and the further analysis we have undertaken. We also explain our decision to include a £41 per customer allowance for unexpected SVT demand costs incurred in cap period seven.

Summary of decision

3.0. We have decided to allow for efficient costs related to unexpected SVT demand, incurred up to the end of price cap period seven[15]. Suppliers have provided diverse views about unexpected SVT demand costs. Having carefully scrutinised the evidence provided by industry stakeholders, we consider in principle that the costs incurred related to unexpected SVT demand are both efficient and material.

3.1. Our decision is to include an allowance for unexpected SVT demand costs of £41, at a weighted average costs level. This weighted average cost level reflects our in the round assessment of all suppliers' evidence related to unexpected SVT demand costs provided as part of this consultation, where costs were incurred, or were likely to be incurred up to the end of March 2022.

3.2. We have not included any costs related to unexpected SVT demand which may materialise during or beyond cap period eight. There was insufficient evidence that these costs were likely to represent a material departure from the cap level during period eight, and evidence provided on this area was limited and highly uncertain. We are also introducing a range of targeted mechanisms to mitigate the risk of unexpected changes in SVT demand from 1 April 2022.

Context

3.3. Recent increases in wholesale prices have led to the available fixed-term contracts (FTCs) in the market being priced well above SVTs. The volume of customers

[15] Most of the costs faced by energy suppliers are expected to occur between August 2021 and March 2022. There was also a very small proportion of costs incurred during June-July 2021 (£500k) which we have had regard to.

choosing to roll-over onto SVTs when their fixed price tariffs expire has increased considerably compared to historic norms.

3.4. Energy suppliers' evidence demonstrates that the number of customers on SVT increased by around 16% during the first three months of cap period seven, ie 1 October 2021 to 1 January 2022.

3.5. There are two primary factors which will determine the extent to which a supplier will face additional costs related to unexpected SVT demand. Firstly, suppliers with a greater starting proportion of fixed customers will be more exposed to additional costs related to unexpected SVT demand. Secondly, a supplier's overall demand forecasting, hedging and risk management arrangements will also be influential in mitigating these costs.

3.6. We also note that suppliers who hedge, even in part, their expected FTC demand in advance of consumers deciding to select a FTC will be less exposed to these costs. This is due to such a supplier being able to offset some or all of the 'unexpected' SVT demand with energy that was originally procured for customers expected to be on FTCs who have since moved to SVTs.

3.7. We would expect suppliers to take mitigating actions (eg through procurement and hedging decisions) based on historical trends. However, we note that suppliers have seen a higher volume of customers move onto SVTs than could have reasonably been predicted and hedged for, especially since August 2021.

3.8. For this higher than expected volume of SVT customers, suppliers will have had to procure this additional demand for delivery in cap period seven at a higher cost (likely above the current cap level) given recent wholesale price increases. It is the demand costs for an unexpectedly higher volume of SVT customers that we consider in this Section.

Summary of stakeholder responses

3.9. Seven suppliers stated that they have faced significant costs linked to unexpected SVT volumes, totalling to around £650m, with individual estimates ranging between £45-£200m. This is due to a greater than expected number of customers defaulting to SVT at FTC maturity and lower than expected customer churn away from SVT. Whilst we appreciate that the cost estimates can differ from one supplier to another, reflecting different SVT forecasting and associated hedging strategies, we do recognise that overall suppliers have faced higher SVT demand than could have reasonably been predicted and hedged for.

3.10. Those seven suppliers recommended an *ex-post* reconciliation, increasing the Wholesale Additional Risk Allowance with an uplift of £14-£109 per default customer in cap period eight.

3.11. Four suppliers noted that costs related to unexpected SVT demand might materialise again in the future and recommended that Ofgem should monitor the situation closely in case another *ex-post* adjustment is needed. We have not included any costs related to cap period eight or beyond as explained in paragraph 3.2 above.

3.12. Four suppliers suggested using weighted average costs rather than a lower quartile approach. These suppliers argued that it would not be appropriate to allow costs at the lower quartile level as unexpected SVT demand costs are not driven by whether a supplier is 'efficient'.

3.13. Two suppliers raised concerns about those customers that joined through the supplier of last resort (SoLR) mechanism. Customers who joined on SVTs through that mechanism are more likely to re-engage with the market and switch to fixed tariffs when FTCs become competitive, leading to supplier losses.

3.14. Two suppliers responded that from spring/summer 2021 they were not able to anticipate higher SVT volumes and therefore adapt their hedging strategies accordingly, as they noticed significant surges with the steep wholesale price increases in September 2021. Those two suppliers argued that their costs might have been higher as they had a significant proportion of FTC customers at the beginning of cap period seven. This was driven by their strategy to actively engage with their SVT customers, encouraging them to shift away from historically more expensive SVT to FTC, in line with Ofgem and Government guidance.

3.15. One supplier stated that they incurred zero costs related to unexpected SVT demand. It is worth noting that this supplier has no customers on FTC.

3.16. A non-industry stakeholder recognised that energy suppliers may be facing unexpected SVT demand. However, they made the point that although costs were higher than anticipated in cap period seven, they may not be in the future. We consider this further supports our decision not to allow an *ex-ante* allowance for these costs, given the uncertainty around whether they will materialise.

Considerations

Setting an efficient benchmark level

3.17. The price cap methodology assumes that energy suppliers can accurately forecast their SVT demand. Consequently, there is no existing specific mechanism to allow the cost recovery for unexpected SVT volume. It is worth noting that those costs have broadly been historically minimal and captured within existing uncertainty mechanisms in the cap. However, costs faced by energy suppliers during cap period seven have been unprecedented and not accounted for, triggering the need for an *ex-post* adjustment.

3.18. Ofgem does not consider suppliers should be penalised for facing higher unexpected SVT demand costs where this is primarily due to having a higher starting share of FTC customers. Similarly, we recognise the challenges that are inherent in forecasting SVT demand in highly volatile markets. In their submissions, many suppliers emphasised the importance of Ofgem not seeking to make judgements on whether a supplier's mitigating actions were 'efficient' with the benefit of hindsight. For that reason, we have determined that setting a benchmark at the lower quartile level is not appropriate in this case.

3.19. We have also carefully scrutinised the mitigating actions and risk management strategies in place. We have determined that, considering everything in the round, all suppliers' evidence provided in this area should be included in the weighted average assessment. We have therefore not excluded any suppliers from the assessment on the grounds of efficiency. However, we note that the strategies of some suppliers were more successful in limiting the extent of these costs than others. We reserve the right to remove a supplier from any similar cost assessment in future if reasonable improvements in their risk management strategies cannot be demonstrated.

3.20. Wholesale price increases have led to the price of FTCs being priced above SVTs from summer 2021. Suppliers have had to purchase additional demand or hedge for a higher-than-expected volume of customers rolling onto SVTs when their FTCs expire. Two illustrative scenarios, described below, could materialise in cap period eight and might require an *ex-post* adjustment in cap period nine:

- in a situation where wholesale prices start to decrease and revert to more 'normal' levels, fixed tariffs become cheaper than SVTs, creating an opposite effect where a volume of customers will switch to FTC. Suppliers that purchased additional demand or hedges to manage unexpected SVT demand will then incur a cost to sell back demand or to unwind hedges that are no longer required due to falling wholesale prices.

- in a situation where wholesale prices remain high, customers might still be choosing to roll-over onto SVTs after their FTC expires at levels higher than supplier forecasts. This will mean that energy suppliers have had to procure this additional demand at a higher cost.

3.21. Ofgem acknowledges that those costs associated with unexpected SVT demand should now be factored in by suppliers in their risk and hedging strategies. As such, any future potential *ex-post* adjustment would build in an improvement in risk management.

Considerations in determining efficient costs

3.22. We note in Section 3.5 that there are two overarching factors which will determine the extent of costs related to unexpected SVT demand. We agree that suppliers should not be penalised for having a higher starting proportion of fixed customers. However, we also conclude that some suppliers were better able to mitigate the costs they would otherwise face with prudent risk management practices, irrespective of the makeup of their customer base.

3.23. Given the evidence submitted as part of this consultation, we have not been able to isolate the proportion of costs incurred due to having a higher starting proportion of FTC customers and those incurred due to having (comparably) less robust risk management strategies in place or being (comparably) slower to respond to the rising wholesale prices. In the absence of the ability to reasonably separate these two factors, we have not excluded any suppliers from our assessment or discounted any level of costs to reflect inefficient actions. We recognise this is a prudent assumption that errs in suppliers' favour, but we consider that any proposed discount to reflect costs incurred due to inefficient risk management strategies would at this stage be arbitrary and not sufficiently backed by the evidence.

3.24. Furthermore, for one supplier, we did have concerns over the validity of some of the evidence provided as demonstrating efficiently incurred costs due to prudent risk management strategies. Nevertheless, the supplier has been afforded the benefit of the doubt and the evidence has been taken into account.

Interaction with supplier of last resort levy claim

3.25. Having reviewed the detailed evidence, and through our engagement with suppliers, we are of the position that the unexpected SVT demand costs we are accounting for in this adjustment do not include any costs which suppliers will reasonably recover through the supplier of last resort (SoLR) levy claims process.

3.26. We will continue to engage with suppliers on this issue and make clear here our expectation that suppliers should not receive the same costs recovered through two means (ie through the SoLR levy claims process and this *ex-post* adjustment).

3.27. Should we encounter evidence, going forward, where Ofgem approved a claim through the SoLR levy process for unexpected demand costs related to SoLR customers and where suppliers have provided evidence to Ofgem through this consultation which included unexpected SVT demand which was already being recovered via a SoLR levy claim, we will seek to adjust the SoLR levy claim on an *ex-post* basis to mitigate the risk of overcompensation. Under the True-up agreement, SoLRs are obliged to correct any inaccuracies and misleading information provided in their initial levy claim and provide a declaration that all information in the true-up is true, accurate and not misleading in any material respect; and Ofgem has the power, on reviewing SoLRs' final claims, to withhold consent if we consider we do not have sufficient evidence to verify the amount claimed.

Risk of unexpected reduction in SVT demand

3.28. We note that this decision focusses on costs related to the unexpected increase in SVT demand in cap period seven. We are also aware of the risk that a fall in wholesale prices could also lead to additional costs for suppliers due to an unexpected reduction in SVT demand.

Methodological considerations

3.29. The weighted average benchmark for costs associated with unexpected SVT demand has been established as follows:

- we have considered energy suppliers' cost estimates up to the end of cap period seven. Those suppliers that have provided Ofgem with cost estimates represent 89% of the GB default customer base. We have excluded costs related to cap period eight.

- we have adjusted those raw cost estimates to 'benchmark consumption values' which are the consumption values used to set the price cap – namely 3,100 kWh for electricity and 12,000 kWh for gas.

- we have split those adjusted cost estimates for electricity and gas, using the same proportions as the gas and electricity wholesale direct fuel allowance for cap period eight, ie 46% for electricity and 54% for gas.

- for each of the eight suppliers[16] that provided cost estimates, we have divided those electricity and gas adjusted cost estimates by their respective numbers of default electricity and gas accounts as of 5 January 2022 from the Financial Responsibility Principle RFI.

- we have calculated the weighted average uplift both for electricity and gas: £18 per SVT electricity account and £23 per SVT gas account. Summed up, that equals to £41 per dual fuel SVT customer.

3.30. We considered whether the costs associated with unexpected SVT demand should be recovered from all residential customers. However, we concluded that even if that alternative approach might be appropriate, there was not enough time to develop an industry-wide levy mechanism and furthermore suppliers' evidence suggests that those historical costs cannot be recovered from the enduring FTC customer base. Nevertheless, Ofgem reserves the right to revisit this issue, and for future adjustments to be made on a market-wide basis.

3.31. We also considered recovering unexpected SVT demand costs across the expected number of default customers as at 1 April 2022, reflecting the fact that the costs which suppliers incur over cap period seven are likely to be recovered over a large customer base. We considered taking a conservative estimate of assuming 60% of

[16] Including the supplier referred to in paragraph 3.15.

FTC expirations would roll onto an SVT between now and end of March 2022. However, we decided not to use an estimated number of default customers in this way, as the approach we have adopted represents a more balanced view of likely default customer numbers across the entire cap period seven, reflecting the risk that SVT customers may move to FTC (if FTC becomes more attractive than SVTs).

3.32. We considered using a lower quartile approach. However, the weighted average option was preferred as we do not consider a lower quartile approach was inappropriate on this occasion. As explained in 3.5 above, one of the primary factors which will determine a supplier's exposure to additional costs related to unexpected SVT demand is their starting proportion of FTC. As this proportion is not linked to a supplier's efficiency, the lower quartile methodology entails the risk of selecting a supplier with a relatively low proportion of FTC that is not necessarily representative of the market as a whole.

4. Backwardation costs

Section summary

We set out stakeholders' responses to our November 2021 consultation on backwardation costs. After considering these responses and conducting further analysis, we have decided to include an allowance for backwardation costs incurred in cap period seven of £8 per customer.

Summary of decision

4.1. We have decided to allow for efficient backwardation costs related to cap period seven, but only to allow for **additional** costs above historical seasonal basis risks. From 1 April 2022, we will allow for cap period seven backwardation costs at the weighted average level based on the evidence provided by industry stakeholders. This will be offset against a 'deadband' that reflects our estimation of what 'normal' basis spreads suppliers would have experienced during cap period seven.

4.2. We estimate the weighted average costs of backwardation for cap period seven to be £24 per customer. However, we estimate that 'normal' basis spreads this winter (through the use of a deadband, explained in more detail in paragraphs 4.20 to 4.22) would have been £16 per customer. As a result, we are allowing the efficient additional costs of backwardation above normal levels, which equates to £8 per customer.

4.3. Suppliers also raised concerns that the current forward curve of wholesale prices suggests backwardation costs for winter 2022/2023 will be much higher than those faced during cap period seven. In Section 7, we set out our intention to consult on a new specific mechanism within the price cap to account for backwardation costs and contango benefits from cap period nine (and onwards).

Context

4.4. The price cap is based on an annual price (of gas and electricity for 12 months) but updated every six months. The price cap level is set using forward prices, using forward contract prices right across the 12 months. This is done to reduce seasonal fluctuations in price.

4.5. This creates 'basis risk' where suppliers over-recover costs in summer and under-recover in winter. Normally the differences in the prices for winter and summer, combined with the increased demand in winter means that this nets out – ie that suppliers are able to recover the full costs in a reasonable period of time.

4.6. When the market is in backwardation the forward prices in the later six months are lower than in the first six (the actual price cap period). It brings the price cap level below the cost to suppliers of purchasing that energy for consumers (for that price cap period). In backwardation the market continues to fall in the next cap period so the under recovery isn't fully corrected in the next cap period. Contango is the opposite of backwardation, when the forward market prices for near-term contracts are lower than prices further in the future, a situation which delivers modest gains to suppliers.

4.7. When we first set the price cap, we assumed that the costs of backwardation and benefits of contango would roughly net off in the long run. However, the long run was not defined.

Summary of stakeholder responses

4.8. Six suppliers provided backwardation cost estimates incurred in cap period seven. Four suppliers explicitly asked for Ofgem to intervene on this issue. All suppliers have provided different estimates of backwardation impact.

4.9. All suppliers provided modelled values for backwardation impact in winter 2021/22. Two suppliers also provided their actual backwardation estimates for cap period seven. We used modelled values in our analysis for consistency.

4.10. A subset of suppliers provided the models used for estimating backwardation impact. From reviewing these, a wide range of approaches were taken, and various assumptions made. These differences are outlined in the Appendix 1.

4.11. One supplier emphasised that historical costs were within tighter range than the forecasted estimates for winter 2021/22 period. That supplier explicitly said that the backwardation estimates in cap period seven deviate from the observed normal spreads. The supplier requested the increased allowance to account for the delta between the margin impact of seasonal spread and the 'normal' spread for that season. Another supplier asked to adjust the price cap for the additional and unexpected costs over the last 6 months. We agree with the argument put forward that any allowance should reflect 'normal' spread costs, where only the additional and unexpected costs are recovered through an additional allowance.

4.12. All suppliers who responded on this issue have criticised the adoption of 6-2-12 approach in exposing suppliers to basis risk. Two suppliers recommended that basis spreads are calculated as a new component on a 6-monthly basis – in this way, requesting a change in methodology from 6-2-12 to 6-2-6. Another supplier supported this request and warned of a risk of a seasonal over/under recovery that will not be offset in the future. A third supplier stated the lack of action would cost £178 per customer in summer 2025 if no action was taken.

4.13. The majority of suppliers asked for a recurring allowance on backwardation to account for the losses, as there is no reason to believe that backwardation costs in volatile markets will be reversed within the life of the price cap. One supplier, on the other hand, proposed a one-off payment for the backwardation impact observed and suggested an amendment to wholesale indexation to reflect the annual equivalent cost under the normal degree of contango.

4.14. Another supplier proposed the introduction of a new mechanism to increase the wholesale allowance when spreads were high, and reduce the wholesale allowance when spreads were low. This mechanism is proposed to come into effect in winter 2022-23 to ensure that the spread exposure (and therefore achieved margins) remain comparable to those envisaged when the price cap policy was designed and introduced.

4.15. Two other suppliers provided their estimates for backwardation costs pre-and post-hedging activity (where they have adopted a hedging strategy specifically to mitigate some of the backwardation costs). We included the pre-hedging cost estimates for both suppliers. We consider this to be a prudent choice that could be made by suppliers to mitigate the costs they face, in line with their overall risk management strategy. Considering the pre-hedging costs in this assessment does not mean this is the approach we would necessarily adopt in any future assessment. In fact, we may determine that using an actual average (reflecting post-hedging estimates where appropriate) may incentivise this behaviour.

4.16. Non-industry stakeholders also expressed their view on matters relevant to backwardation costs. Two stakeholders asked for the default tariff cap increase to be reflective of the wholesale price volatility. They explicitly asked for the allowance to be symmetrical, ie for it to decrease if prices were to fall. We consider this suggestion as valid and have included it in the considerations below.

4.17. One stakeholder emphasised the role which hedging strategies play in suppliers' response to price volatility. This stakeholder urged that amendments to the default tariff cap should not disincentivise hedging. We agree that amendments to the price cap should not distort suppliers' incentives for adopting prudent risk management strategies such as hedging.

4.18. Another stakeholder suggested that Ofgem should explore the opportunity of changing the price cap methodology by amending the observation window, and thus considering nearer to real time wholesale prices. However, this stakeholder also warned of the risks around exposing consumers to more volatile prices.

Considerations

Setting an efficient benchmark level

4.19. In our November 2021 consultation, we stated that we are open in principle to the prospect that backwardation costs may have materially departed from the efficient cost level. We sought evidence from industry on the current backwardation costs. Having scrutinised the supplier evidence, we consider that these costs represent a clear, material, and systematic departure from the price cap level for period seven. Given the pace and scale of wholesale price increases, these costs may not be offset by the benefits of contango within the lifetime of the price cap.

4.20. Evidence from suppliers supports the view that the backwardation costs have deviated from the price cap level. Most suppliers have indicated that backwardation costs are materially higher in cap period seven, due to the recent wholesale price increases in 2021, and exceed those in previous cap periods. Various suppliers have provided quantitative estimates for backwardation costs in cap period seven, ranging from £16 to £35 per customer per year.

4.21. We do not consider that it is in consumers' interests to allow the full costs of backwardation for cap period seven. Our internal analysis suggests that, since the price cap was introduced, the seasonal basis spreads have broadly netted off over time - until period seven. If backwardation costs were within normal historical ranges for period seven, there would be limited justification for allowing backwardation costs to be recovered, as these costs would be broadly offset by future periods of contango.

Use of deadband

4.22. We determined that consumers should only bear the cost of **additional** backwardation costs incurred related to cap period seven. We have calculated a deadband to quantify an estimation of 'normal' backwardation costs that we would expect suppliers to incur during cap period seven.

4.23. We have calculated this deadband by taking the mean modelled backwardation and contango costs across a three-year period, covering cap periods one through six. We then created a deadband at one standard deviation around this mean. This deadband equates to £16. This means that under normal market conditions, we would expect backwardation costs up to £16 for cap period seven. We set out more detail on this deadband approach below in paragraph 4.26.

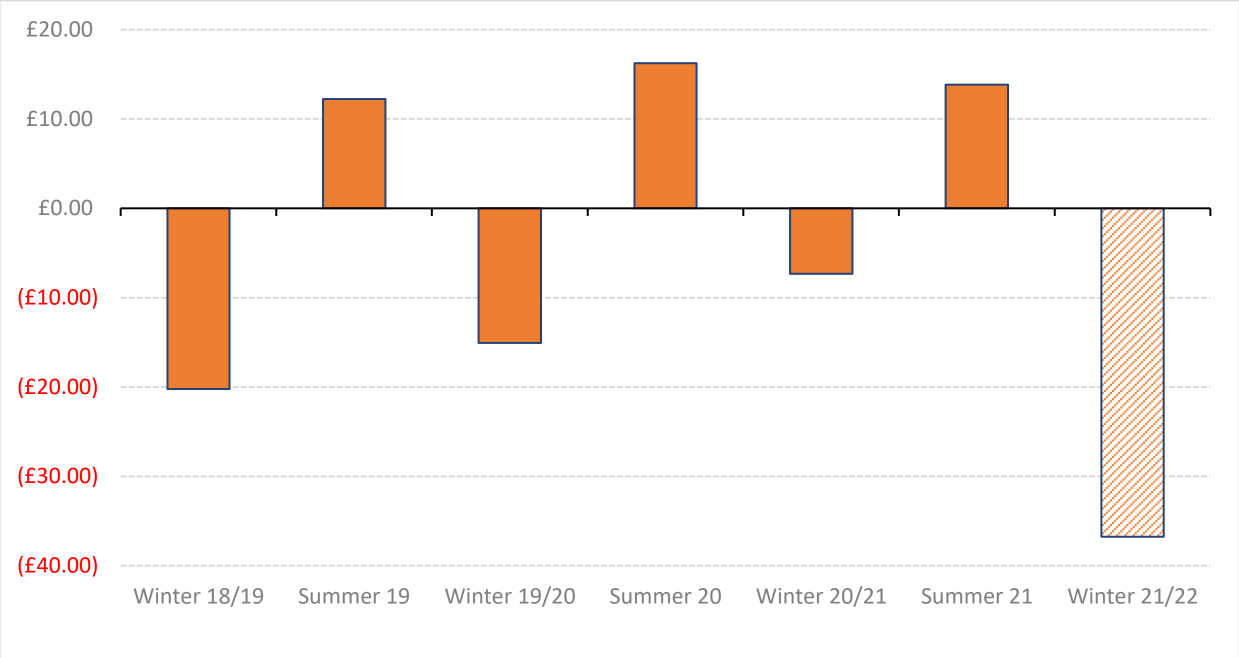
4.24. We also considered using an Ofgem modelled value for backwardation costs incurred during period seven, using the same deadband as set out above. We note this would ensure the deadband methodology was comparable and consistent with the period seven estimate. However, we note that we did not have sufficient historical evidence from suppliers to calculate a deadband based on supplier representations. We also consider, on this occasion, that relying on a modelled approach is likely to be less cost reflective than relying on supplier evidence. Allowing for costs provided by supplier evidence at the weighted average level (rather than Ofgem modelling) wherever possible is also consistent with the methodology adopted in other cost areas for this decision.

Methodological considerations

4.25. Since the publication of the November 2021 consultation, we have conducted our own analysis of basis spreads in cap period one to seven. We compare a 6-2-12 price indexation, the basis on which the price cap is set, to a 6-2-6 hedging strategy. We do this for each price cap period. Under-recovery is observed in each winter period, with over recovery in each summer period - ie basis risk. Our analysis confirms the validity of the assumption we used when we first set the price cap that basis risk costs and benefits are close to netting off until cap period six. We recognise that the impact with respect to cap period seven materially diverges from previous price cap periods.

4.26. Figure 1 below shows the historic and modelled (estimated) costs and benefits of basis risk over the first six price cap periods. Modelled period seven costs are represented by the patterned bar.

Figure 1: Modelled estimate of basis risk costs



Accessible format

Figure 1 represents the backwardation costs and contango benefits observed in cap periods one to seven. The values presented are for dual fuel (cumulative for gas and electricity). For the first six cap periods backwardation is observed in each winter, and contango is observed in each summer. In cap period seven, winter 2021-2022, saw an unprecedented increase in magnitude of backwardation costs.

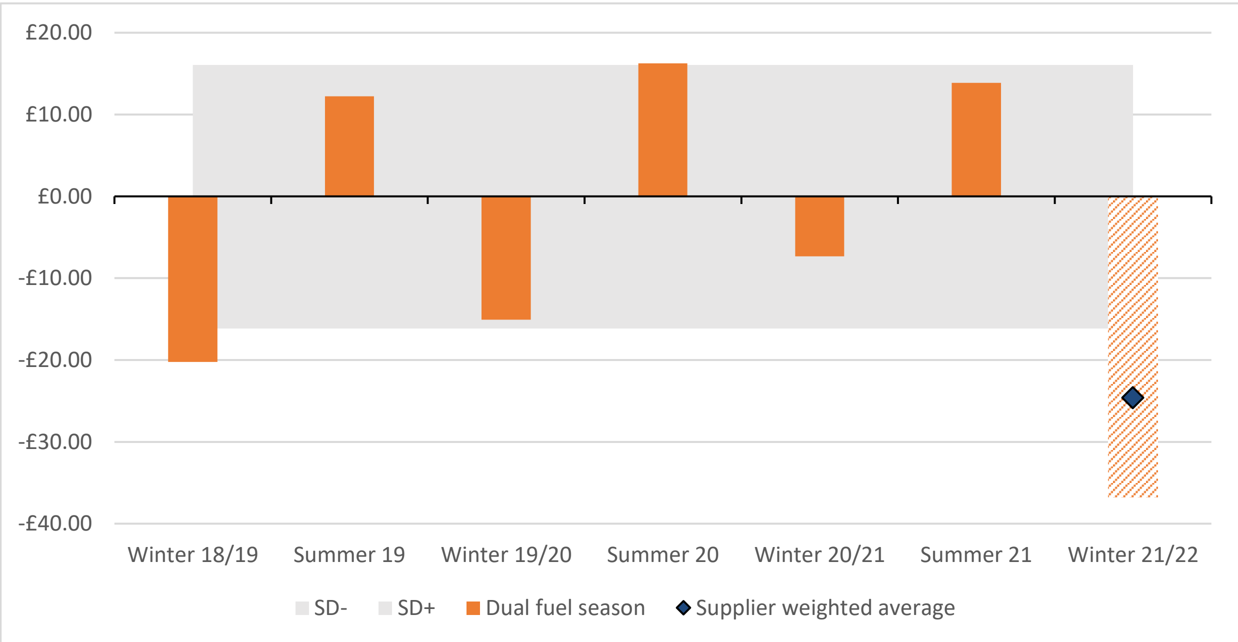
4.27. As can be seen above, we would expect there to be otherwise unrecoverable costs associated with backwardation in cap period seven. The existing methodology allows for 'normal' backwardation costs to be recovered, through comparable periods of contango. As part of this consultation process, we have developed an approach of applying a 'deadband' to ensure default customers only pay for efficient and material costs that are not already accounted for in the existing price cap methodology. We intend for this 'deadband' to accommodate a 'normal' range of fluctuations that an efficient supplier would absorb or mitigate.

Approach to calculating a deadband

4.28. We consider it appropriate to use the average basis variation observed in cap periods one through six as the basis to calculate a deadband. We set the upper boundary as the average plus the standard deviation (£16/customer/year) and the lower boundary as the average minus the standard deviation (-£16/customer/year). As previously assumed, the calculated average (£0.04) is a small number and can be absorbed by the uncertainty allowances. The calculation of the deadband is set out in Figure 2.

4.29. Figure 2 presents the comparison of basis risk estimates (£/customer/year). The solid orange bars show historical data, whilst patterned bar shows the modelled values for period seven. The point value contained within the cap period seven modelled estimate represents suppliers' weighted average (by the number of SVT customers) of estimates submitted to Ofgem. The grey area along the x-axis represents the deadband.

Figure 2: Use of deadband to define a normal range of backwardation costs



Accessible format

Figure 2 represents the dynamics of backwardation costs and contango benefits observed cap periods one to seven, compares our modelling to supplier's weighted average and introduces the notion of a deadband. For the first six cap periods backwardation is observed in each winter, and contango is observed in each summer. However, for cap period seven an unprecedented increase in magnitude of backwardation is projected. A supplier weighted average value (by SVT customers) presents suppliers' projection of backwardation impact expected in cap period seven, which is also a considerably greater cost than previously observed values. To calculate the allowance, a deadband was applied based on average variation observed in cap period one to six.

4.30. Calculating the weighted average of supplier backwardation costs in cap period seven equates to (-£24/customer/year). This value is based on cost estimates from suppliers representing 74% of the market (measured by the number of SVT customers). Subtracting the lower boundary deadband (-£16/customer/year) determines an allowance for backwardation costs in cap period seven of -£8/customer/year.

4.31. **Alternative approach to calculating deadband** – we also considered using the min/max values from period one through six to calculate the deadband range. However, we decided not to introduce such a deadband on the basis that it would represent the worst case scenario, and in all circumstances was not an appropriate approach.

Differentiating by fuel type

4.32. We have decided to calculate the backwardation allowance on a dual fuel basis (against a dual fuel deadband), and then allocate the allowance to electricity and gas based on the relative size of the modelled backwardation effect for each fuel.

4.33. After reviewing supplier responses to November consultation, we noted that all suppliers have provided backwardation estimates for dual fuel, with a small subset of suppliers adding further differentiation by fuel in the evidence submitted.

5. Shaping and imbalance costs

Section summary

We set out stakeholders' responses to our November 2021 consultation on shaping and imbalance costs. After considering these responses and conducting further analysis, we have decided to include an allowance of £12 per customer for shaping and imbalance (electricity) costs incurred in cap period seven.

Summary of decision

5.1. We consider there is evidence that suppliers have incurred material additional costs due to shaping and imbalance costs for electricity in cap period seven. We have decided to allow an adjustment of £12 from cap period eight to reflect the material and efficient shaping and imbalance costs incurred during cap period seven which were not adequately accounted for within the relevant existing additional direct fuel allowances for shaping and imbalance related costs.

5.2. We are allowing additional shaping and imbalance costs at the weighted average cost level for electricity only, as we do not believe there is sufficiently clear evidence that gas shaping and imbalance costs have materially departed from the level allowed in the price cap level. We have decided not to include any *ex-ante* allowances for cap period eight relating to shaping and imbalance costs beyond those incurred during cap period seven.

5.3. Our current view is that the increase in additional direct fuel allowances for shaping and imbalance £29 for cap period eight is likely sufficient for suppliers to recover their efficient costs. That is on the basis it remains uncertain whether current levels of volatility will continue through period eight. Suppliers will see an increase of £16 on electricity shaping and imbalance and £13 on gas shaping and imbalance from 1 April 2022 through the existing shaping and imbalance indexed allowance.

5.4. We are minded to consult further on potential changes in the methodology used to set the shaping and imbalance allowance in 2022.

Context

5.5. Shaping and imbalance costs relate to the costs suppliers face of refining their hedge positions from less to more granular contracts closer to delivery. The cap methodology currently assumes that these costs represent the same proportion of direct fuel costs in any given cap period.

5.6. Shaping costs will depend on wholesale prices near to consumption, and how these compare to the price at which a supplier bought the bulk of its wholesale energy (ie its direct fuel costs). As wholesale spot prices have increased sharply, we expect the costs of shaping and imbalance may therefore have also increased during the current cap period.

Summary of stakeholder responses

5.7. The majority of suppliers have indicated that shaping and imbalance costs were materially higher than the cap allows for in cap period seven due to increased wholesale prices during winter 2021. The justification for this has included scarcity pricing, the increased cost of imbalance positions, increased prices in Block 5, demand impacts due to COVID-19 and increased market illiquidity.

5.8. There were a few notable exceptions, with two suppliers remarking that only modest impacts were felt overall in terms of shaping and imbalance costs owing to their hedging strategy and the unusually warm autumn.

5.9. Overall, several suppliers indicate that some form of adjustment is warranted to enable recovery of additional costs over and above the shaping and imbalance allowance in cap period seven.

5.10. Eight suppliers have provided estimates of what they think increased cap period seven shaping and imbalance costs will be.

5.11. Several suppliers chose not to provide estimates of gas shaping and imbalance costs, instead focusing their evidence on electricity only. Those that did provide gas-related evidence gave an inconsistent view of gas shaping costs. One supplier suggested the existing gas shaping allowance resulted in over-recovery for cap period seven, not under-recovery, while some supplier responses suggested minimal or no changes.

5.12. One supplier raised that it was unclear whether the impact of changes to prepayment meter End User Categories (EUCs) would be taken into account for gas shaping allowances in the upcoming period.

5.13. Some suppliers have stated that the shaping and imbalance allowance has been insufficient over several periods historically, and that the current indexed methodology will not enable sufficient recovery of shaping costs. Justification for this included: the shaping costs being indexed based on 2014-2018 data, rises in the expected levels of similar costs priced into fixed term tariffs, and changes in market fundamentals (eg price volatility and risk).

5.14. Various alternative methodologies have been put forward by suppliers to prevent systematic under-recovery of costs. These included basing assessments on the weighted average of suppliers' actual out-turns for cost categories, having different allowances for different elements of shaping and imbalance costs, and using only prices close to the observation window rather than an average cost over the whole observation window.

5.15. We agree that a review of the existing shaping and imbalance allowance indexation methodology is warranted, and we will be doing so via consultation this summer.

5.16. Other stakeholders have highlighted that while shaping and imbalance costs may be higher than anticipated at this time, this may not carry forward into the future. We agree that the uncertainty around forward costs and future levels of volatility should be taken into consideration and have done so in our assessment of whether to make any *ex-ante* interventions.

Considerations

Setting the efficient benchmark level

5.17. We recognise that the energy markets have seen a marked increase in volatility in the past year, and that this has translated to a material increase in electricity shaping costs incurred during cap period seven. We have decided to allow for efficiently incurred shaping and imbalance costs in line with those set out in our minded-to decision of November 2021.

5.18. We agree that our adjustment should reflect actual costs incurred by suppliers. Supplier evidence showed a significant variation in cost impact, with some noting no or negligible effects on shaping and imbalance, and others suggesting impacts in excess of Ofgem's proposed £5-20/customer.

5.19. We have decided to use the weighted average of supplier estimates to set our adjustment of £12 to the Wholesale Additional Risk Allowance for electricity. Those suppliers that have provided Ofgem with shaping and imbalance cost estimates represent 83% of the GB domestic market for electricity (also 83% of GB default customer base for electricity). We think this is the most appropriate approach to approximate overall impacts, as it weights the impact of each suppliers' estimates (where provided) based on their SVT customer account base.

5.20. An alternative consideration was the use of a lower quartile approach to set the efficient benchmark for shaping and imbalance costs, as in principle suppliers can to some extent mitigate against these costs by using prudent hedging strategies and improving forecasting accuracy. However, given the exceptional nature of the energy crisis, and reflecting the fact that some suppliers may have incurred gas shaping and imbalance costs, we believe there is reason to err on the side of using a more conservative weighted average approach.

5.21. To calculate the adjustment, we have reviewed supplier data on their cap period seven cost increases and the corresponding narrative provided. It is worth noting that suppliers reported these in a variety of ways, ranging from detailed impact breakdowns to more aggregate headline impacts which did not split by fuel type. As much as possible, we have relied on a review of the supporting narrative to ensure only efficiently incurred costs due to increased wholesale volatility were included. Following this, we have applied a weighted average based on SVT customer base, consistent with the approach to unexpected SVT drift costs and backwardation. For more details on the steps taken, please refer to Appendix 1.

Differentiating by fuel type

5.22. We have decided not to allow additional adjustments for gas shaping and imbalance allowances as supplier evidence was inconclusive and inconsistent in this regard.

5.23. In reaching our decision not to make any adjustments to the gas shaping and imbalance allowances but to do so for electricity, we undertook internal analysis to get a view on whether existing indexation levels are materially lower than those implied by the latest data for cap period seven (holding the existing shaping and imbalance methodology constant). Our results supported the view that gas shaping costs have not materially increased, and in fact there is some evidence that the shaping and imbalance indexed allowances for gas may represent a systematic over-recovery.

5.24. In the absence of robust and conclusive evidence from industry, and having regard to Ofgem's internal analysis, we do not consider there is sufficient evidence that gas shaping and imbalance costs represent a material departure from the cap level during cap period seven.

Potential for additional shaping and imbalance during period eight

5.25. We do not consider there is sufficient justification for allowing an *ex-ante* cost allowance for additional shaping and imbalance costs that may be incurred during cap period eight. This is on the basis that it is uncertain whether the current levels of volatility will continue. Furthermore, even if shaping and imbalance costs are comparable in cap period eight to those in cap period seven, the increase in the shaping and imbalance allowance expected from 1 April, £29 is expected to ensure suppliers can recover these costs.

5.26. Our initial internal analysis on this area suggests that the current shaping and imbalance indexed allowances may introduce a systematic over-recovery of gas shaping and imbalance costs combined with a comparable under-recovery of electricity shaping and imbalance costs. We therefore propose to consult on an update to the shaping allowances in time for cap period nine. We may also consult on the impact of the new EUCs on gas shaping allowances within this consultation.

Methodological considerations

5.27. To calculate our proposed adjustment of £12 we reviewed supplier data on their cap period seven cost increases and the corresponding narrative provided. Suppliers reported these increases in a variety of ways, ranging from detailed impact breakdowns to more aggregate headline impacts which did not split by fuel type. As much as possible, we have relied on a review of the supporting narrative to ensure only efficiently incurred costs due to increased wholesale volatility were included. Following this, we have applied a weighted average based on SVT customer base, consistent with the approach to unexpected SVT drift costs and backwardation. For more details on the methodological steps taken, please refer to Appendix 1.

6. Contracts for Difference (CfD) and other costs

Section summary

We set out stakeholders' responses to our November 2021 consultation on Contracts for Difference (CfD) and other cost categories. After considering these responses and conducting further analysis, we have decided not to include any additional adjustment to reflect CfD or other costs.

CfD costs

Summary of decision

6.1. We have decided to not include an offset for CfD benefits on the basis that the majority of suppliers submitted in their responses that they did not experience this benefit, as they fully hedged their CfD cost exposure.

6.2. We did not receive representations on this issue from all suppliers who responded to the consultation. However, from the responses we did receive, six suppliers who fully hedged their CfD cost exposure represent over 70% SVT customers in the market.

6.3. We are minded to review, on a forward-looking basis for cap period nine (and onwards), whether any CfD benefit actually experienced by suppliers (ie due to the interim levy rate floor of £0/MWh) should offset any forward-looking costs associated with high wholesale electricity prices.

Summary of stakeholder responses

6.4. Six suppliers noted that they hedge their CfD cost exposure.

6.5. One supplier recommended a £0.70/MWh (equivalent to £2 per customer) uplift to account for the under forecasting of capture price costs in the interim levy rate used to set the winter 2022 cap.

6.6. One supplier noted that they support our approach of netting off CfD costs and agreed the calculations set out in our November 2021 consultation were accurate.

Considerations

6.7. Based on the importance of suppliers having robust risk mitigation processes in place (including hedging), we agree with industry stakeholders that including a £15 - £20 offset, as set out in our November 2021 consultation, would in effect penalise suppliers with prudent risk management strategies in place.

6.8. We note that some suppliers will have made a commercial decision not to hedge CfD costs and will have experienced a material benefit. However, under the statutory regime, the price cap cannot be set at different levels for different suppliers. On that basis we consider the balance of risk is strongly in favour of ensuring the majority of the suppliers, who have hedged CfD costs, are able to finance their efficient activities, noting that a small portion of the market will over-recover relative to the CfD allowance for periods six and seven.

Future reform on CfD cost allowance

6.9. The quarterly interim levy rate, which is used to determine the CfD allowance in the price cap, has a floor of £0/MWh as prescribed in secondary legislation (The Contracts for Difference (Electricity Supplier Obligations) Regulations 2014 as amended from time to time). When wholesale prices are materially higher than the CfD strike price for an extended duration, suppliers will receive a payment from generators via the Low Carbon Contracts Company (LCCC), rather than suppliers paying generators when wholesale prices are below the strike price. Since the start of the cap, wholesale prices have not been typically higher than the CfD strike price for a sustained period, so the interim levy rate forecast has always been a positive value in previous cap periods. However, for at least cap period eight, the interim levy rate which will determine the CfD cost allowance, will be £0/MWh. This means suppliers will experience a benefit (through a return of levy payments from generators via LCCC) that will not be accounted for in the price cap for period eight.[17]

[17] LCCC (2022), Advanced interim levy rate forecast. https://www.lowcarboncontracts.uk/dashboards/cfd/levy-dashboards/15-month-forecast

6.10. We estimate suppliers will receive an estimated benefit of £7 per customer (or £2.2/MWh) in annualised terms from cap period eight if they hedge in line with the interim levy rate forecast.

6.11. We do not propose to claw back this £7 benefit to suppliers for period eight through a negative adjustment. Since this issue was not raised in our original consultation, and as it relates primarily to cap period eight, we consider this £7 potential benefit may offset other additional and uncertain costs which suppliers may incur during period eight related to wholesale market volatility.

6.12. However, going forward, we propose to amend how the CfD allowance is calculated to ensure it remains reflective of the CfD related costs (and benefits) suppliers face and to ensure the CfD allowance is robust to wholesale market volatility. We will publish a consultation during cap period eight to propose a new methodology to set the CfD allowance.

RO mutualisation

Summary of decision

6.13. Whilst RO mutualisation was not referred to in our November consultation document, several suppliers responded with concerns that the price cap does not adequately reflect the cost of RO mutualisation.

6.14. We agree that RO mutualisation costs have increased for the relevant scheme year (2020/21) which includes cap period seven. We estimate RO mutualisation cost for cap period seven to be ~£2.70 per customer. However, we note that the headroom allowance will increase by £8 for cap period eight, and this increase will be beyond the actual cost increase related to costs captured within the headroom allowance. We do not propose any further adjustment to the headroom allowance for RO mutualisation.

Summary of stakeholder responses

6.15. Six suppliers expressed concerns that the current cap methodology does not adequately resolve the ~£218m mutualisation shortfall in cap period seven.

6.16. Three suppliers estimated a shortfall impact ranging from £2 to £7 per domestic customer.

Considerations

6.17. Although RO mutualisation costs have increased relative to previous cap periods, in our estimation, the headroom allowance increase of £8 from period seven is sufficient to account for the ~£2.70 RO mutualisation costs. Again, we have also had regard to the prudent assumptions made throughout this decision which err on the side of ensuring suppliers can finance their efficient activities.

6.18. RO costs have historically been allocated to the headroom.[18] Recently we have also considered whether RO costs require an additional allowance. In our COVID-19 consultation[19], we held the view that the headroom allowance was sufficient to cover RO costs. Now, we also conclude that RO costs are still within the headroom allowance. Even though the RO costs have increased materially, the headroom allowance has increased considerably beyond £8. We have also had regard to the prudent assumptions we have taken throughout this decision in reaching this conclusion.

Other cost categories

Summary of decision

6.19. Some industry stakeholders have provided representations that they face higher costs related to wholesale market volatility other than the cost categories discussed in our consultation. These include, but are not limited to, Unidentified Gas (UIG) costs and transaction costs. We refer to costs not explicitly discussed in our November 2021 consultation broadly as 'other costs' in this Section.

6.20. Upon reviewing the evidence provided relating to other costs, we do not consider that any further adjustment is required to ensure suppliers are able to recover their efficient costs related to these activities. We are therefore not including other costs in our adjustment to the Wholesale Additional Risk Allowance, as we do not consider these costs to represent a material departure from the cap level due to wholesale

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[18] Ofgem (2018), Default tariff cap: decision – overview, Appendix 2 - Cap level analysis and headroom, paragraph 3.86. https://www.ofgem.gov.uk/sites/default/files/docs/2018/11/appendix_2_-_cap_level_analysis_and_headroom.pdf

[19] Ofgem (2020), Reviewing the potential impact of COVID-19 on the default tariff cap: November 2020 consultation, paragraph 6.90. https://www.ofgem.gov.uk/publications/reviewing-potential-impact-covid-19-default-tariff-cap-november-2020-consultation

market volatility. We note that only a small number of suppliers made representations on any of these costs, suggesting that the issues raised were not faced by or at least significant for others.

6.21. Where suppliers face additional costs, we expect the existing allowances and uncertainty mechanisms within the cap to account for these. We also note that we have made a number of prudent assumptions in suppliers' favour in setting the level of adjustment which we have had regard to in considering whether to allow for other costs. This includes, for example, deciding not to offset the £5 Wholesale Additional Risk Allowance (that was in place during period seven) to account for uncertain wholesale costs. We also consider that the increase in indexed allowances, including headroom, will ensure that suppliers are able to finance their efficient activities for these areas without the need for further adjustment.

Summary of stakeholder responses

6.22. One supplier estimated that the costs from Balancing Services Use of System (BSUoS) charges are out-turning higher than the cap currently allows for, leading to under-recovery of efficient costs.

6.23. One supplier recommended an adjustment to the transaction cost calculation of £5 per domestic customer to reflect an electricity increase from 0.39% to 1.1% and a gas increase from 0.32% to 0.9%.

6.24. One supplier recommended an increase to the profit margin on the basis that the 1.9% EBIT as considered by the Competition and Markets Authority (CMA) to reflect a fair margin is not sufficient.

6.25. Two suppliers recommend uplifting UIG from the current 2% allowance. One supplier forecasts future UIG volume above 4%.

6.26. One stakeholder raised concerns regarding suppliers defaulting within the BSC and the possible consequential impact of any failing suppliers' debts (relating to credit cover) being mutualised across the market in future cap periods.

6.27. One stakeholder agreed with our proposal that capacity market costs are already appropriately accounted for in the current cap methodology.

Considerations

6.28. We note that BSUoS will pass through future cap periods via the existing methodology. The capping of BSUoS costs has been approved within modification CMP381 (Defer exceptionally high winter 2021/22 BSUoS costs to 2022/2023)[20] which limits BSUoS to a maximum of £20/MWh subject to a total maximum deferral of £200m.

6.29. Having reviewed the evidence, we do not consider that transaction costs were materially higher in cap period seven than the existing cap methodology accounted for. However, we also note that the decision not to offset the £5 Wholesale Additional Risk Allowance may contribute to higher than normal transaction costs for any particular suppliers, who may have faced higher costs when compared to the market as a whole.

6.30. We outlined our position on EBIT in our November 2021 consultation. Our position remains that any increase to the overall cap for cap period eight will lead to an increase in EBIT as the 1.9% will be indexed to a higher cap level.

6.31. We outlined our position on UIG in our November 2021 consultation, stating that UIG is being considered separately as part of our EUC consultation,[21] therefore is out of scope of this consultation.

Bad debt

Summary of decision

6.32. Whilst bad debt was not referenced in our November 2021 consultation document, we are mindful that bad debt is becoming an increasing risk for suppliers based on current market conditions, and the expected increase to customers' bills from 1 April 2022. A small number of respondents referenced bad debt in their submissions. Those who did raised a broad concern rather than any cost estimate.

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[20] National Grid ESO (2022), CMP381: Defer exceptionally high Winter 2021/22 BSUoS costs to 2022/2023. https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp381-defer

[21] [21] Ofgem (2021), Consultation on reflecting prepayment End User Categories in the default tariff cap. https://www.ofgem.gov.uk/publications/price-cap-consultation-reflecting-prepayment-end-user-categories-default-tariff-cap

6.33. Based on this, we do not believe there is enough material evidence at this stage to warrant an *ex-ante* inclusion of bad debt within the cap.

Summary of stakeholder responses

6.34. Two suppliers raised concerns of not being able to recover the increased costs they have incurred during cap period seven, of which rising levels of bad debt is a factor (primarily driven by impacts of COVID-19 on customer affordability). Both recommended that a potential mechanism should be considered if exceptional increases to bad debt occur within the market.

Considerations

6.35. We will continue to monitor the material impact of bad debt and its impact on the market. We may make further adjustments in the future if needed.[22]

[22] We will consider the appropriate way forward in the circumstances. Our approach may differ from our previous COVID-19 adjustment.

7. Future reform of the price cap

Section summary

We describe our plans to make specific changes to the price cap methodology ahead of cap period nine as well as broader changes to the price cap methodology.

Changes to the price cap methodology ahead of period nine

7.1. Following on from this decision, we are exploring further specific reforms to several areas of the price cap to ensure it more accurately reflects the costs facing suppliers on an enduring basis and is robust to volatile market conditions.

7.2. During cap period eight, we intend to consult on the following areas, including minded to positions to amend the existing cost allowances, ahead of period nine:

- **Amending the CfD cost allowance** – Over the coming months we will consult on proposals for amending the CfD allowance, including a minded to position to move away from the current methodology of calculating the CfD cost allowance to an approach that more appropriate reflects the costs (and benefits) to suppliers related to CfD payments. Our current expectation is that any adjustment following this consultation will take effect from price cap period nine.

- **Amending the additional direct fuel allowances for shaping and imbalance costs** – Over the coming months we will consult on proposals for amending how the costs related to shaping and imbalance are accounted for in the cap. We expect to include a minded to position to move away from the existing fixed uplift approach to an alternative mechanism that more closely reflects the underlying costs of these activities, particularly when markets are volatile. We may also consider reflecting the change in prepayment meter (PPM) EUCs in the gas shaping methodology. Our current expectation is that any adjustment following this consultation will take effect from price cap period nine.

Broader changes to the price cap methodology

7.3. In addition to the above, we are today publishing a policy consultation on fundamental changes to the design of the price cap.[23] This consultation seeks stakeholders' views on a number of changes to the overarching design of the price cap, with the objective of reducing the scale of risks facing the industry and delivering a lower cap level for consumers.

7.4. The options being consulted on include:

- **Three options to improve the robustness of the price cap methodology:**
  - **A strengthened status quo / reduced notice period** - As per the current price cap tariff (which has a six-month cap period) but with a reduced notice period of one month (from the current two). It is enhanced further through the ability to, in extreme circumstances, adjust the price cap in-period.
  - **Quarterly updates** - Moving to quarterly price cap updates or updating every four months (in place of the current six-monthly updates).
  - **Price Cap contract** - A six or 12 month cap with no exit fees which would close to new customers at the end of each month, with a new level based on more current wholesale energy costs opening to new customers in the following month, and in each successive month after that.

- **A new mechanism for managing backwardation costs and contango benefits** – Introducing a new specific mechanism to compensate suppliers when they incur excessive backwardation costs (or receive an excessive overcompensation when the market is in contango). Should our consultation process determine such a mechanism is in consumers' interests – we expect such a mechanism to be in place from 1 Oct 2022.

[23] Ofgem (2022), Consultation on Medium Term Changes to the Price Cap Methodology. https://www.ofgem.gov.uk/publications/consultation-medium-term-changes-price-cap-methodology

- **Reduced notice period** – Moving to a shorter notice period between when the price cap levels are announced and when they take effect.

7.5. We set out more detail on these proposals (and timing implications) in the policy consultation and welcome feedback from all stakeholders.

Appendices

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Appendix 1: Methodology and supplier model review

Overview

1.1. This appendix describes our approach to the calculating the uplift in the wholesale risk allowance to implement the Wholesale Additional Risk Allowance allowed costs incurred in cap period seven. It also includes our review of the cost models submitted by certain suppliers, for each area. We also provide further details on our analytical approaches supporting unexpected Standard Variable Tariff (SVT) demand costs, backwardation costs, and shaping and imbalance costs.

Approach to calculating the uplift

1.2. In Section 2 we set out our decision on the mechanism for allowing additional costs incurred by suppliers in cap period seven. We decided on Option 1: to amend the wholesale risk allowance, by revising the indexed value of the wholesale risk allowance, that is currently set at 1% of direct fuel costs.

1.3. To make this adjustment we convert the £61/customer/year allowance into a percentage adder and then add it to the 1% Wholesale Additional Risk Allowance for cap period eight in our Annex 2 model. The Annex 2 model calculates the direct fuel cost component of the cap.

1.4. We have adjusted the % uplift to the Wholesale Additional Risk Allowance to account for losses and UIG. For electricity, the uplift is set such that the average wholesale risk increase is £34 after accounting for losses. We account for electricity losses based on GB average losses across the 14 demand regions. For gas, the uplift is set so that the increase is £27 after UIG is accounted for.

1.5. Table 2 in Section 2 sets out the additional allowance for unexpected SVT demand, backwardation and shaping and imbalance by fuel type. The approach to calculate the fuel type split for each allowance is described in that respective Section of this decision[24]. Table

[24] Section 3: unexpected SVT demand costs, Section 4: backwardation costs, Section 5: shaping and imbalance costs.

4 shows these allowances by fuel type and by meter type for electricity and payment type for gas[25].

1.6. Each percentage adder is calculated to make sure the applicable cap period seven allowance is recoverable from the benchmark level of annual consumption for each fuel type and meter or payment type.

Table 4 – Allowance uplift calculations

Fuel type	Meter or payment type	P7 allowance (£/customer/year)	P7 allowance (%)	P8 plus P7 allowance (%)
Electricity	Single rate	£34.37	7.68%	8.68%
Electricity	Multi register	£34.37	5.66%	6.66%
Gas	Gas Non-PPM	£26.79	5.05%	6.05%
Gas	Gas PPM	£26.79	4.89%	5.89%

Unexpected SVT demand costs

Supplier model review

1.1. Eight suppliers provided cost estimates associated with unexpected SVT demand for cap period seven. In terms of evidence for these estimates: three suppliers provided a model, one supplier provided a breakdown of proposed uplifts by fuel component, three suppliers provided high level estimates, and one supplier stated that they incurred zero costs.

1.2. As described in paragraphs 3.0 and 3.2, we have regarded costs incurred up to the end of cap period seven and not considered costs estimated for cap period eight or beyond.

1.3. As detailed in paragraph 3.29, we had to adjust some cost estimates to benchmark consumption values; 3,100 kWh for electricity and 12,000 kWh for gas per year.

1.4. Three suppliers provided additional evidence regarding the split of unexpected SVT demand costs between electricity and gas. Since the *ex-post* adjustment is levied during

[25] Electricity consumers with a single rate metering arrangement or a multi register metering arrangement. Gas consumers without a prepayment meter (Non-PPM) and with prepayment meters (PPM).

cap period eight, it was further decided to use the wholesale direct fuel allowance ratio for this particular cap period, ie 46% for electricity and 54% for gas.

1.5. To calculate the weighted average unexpected SVT demand costs allowance for cap period eight, we used the number of SVT accounts for each fuel as the weights, as described in paragraph 3.29.

Backwardation costs

Supplier model review

1.6. Six suppliers provided estimates of backwardation costs incurred in cap period seven. Three suppliers provided models to evidence their estimates. The other three suppliers provided high level estimates of backwardation for cap period seven.

1.7. It is worth noting the differences in suppliers' approaches to modelling backwardation costs. One supplier's model was similar to Ofgem's in-house model, accounting for shaping and imbalance allowances and transaction costs. This model used the same spread splits and data source for forward prices data. However, the current TDCV value of 2.9 MWh was used, rather than the benchmark value of 3.1 MWh used for the price cap. This was a driver of the difference in the final estimates for dual fuel.

1.8. However, two suppliers' models were different to Ofgem's model. Another supplier's model did not differentiate between gas and electricity product spreads, as well as disregarding differences between peak and baseload electricity prices, using the averages for baseload in its modelling. This model also did not account for shaping and imbalance allowances, transaction costs, regional losses, and the benchmark metering arrangements (single-rate and multi-register). A third supplier's model did not take into account peak/base demand difference in electricity forward prices. The model did not differentiate between time periods (quarter/season) for the gas and electricity products and did not specify which of the two were used (calling the products 'Product 1', 'Product 2', 'Product 3' and 'Product 4'). This supplier's modelling approach did not include shaping and imbalance allowances, transaction costs, regional losses, or the benchmark metering arrangements (single-rate and multi-register) either.

1.9. Some suppliers provided multiple estimates for backwardation costs in cap period seven. For consistency purposes, we have taken the pre-hedging estimates where possible. In our modelling, we have used the weighted average value for backwardation costs, where the weight is the number of SVT customers each supplier has, leading to a value of £24.

Methodological choices

1.10. This Section explains our methodological choices that inform our decision to provide an £8 allowance for backwardation costs incurred in cap period seven, which we describe in Section 4.

1.11. To calculate backwardation costs or contango benefits in each cap period, we compare a 6-2-12 price indexation to a 6-2-6 hedging strategy. We chose 6-2-12 as this is the basis on which we set the price cap. Although a range of other hedging strategies are possible, we chose 6-2-6 as the comparator as this was the most common hedging strategy suppliers' consultation responses said they used in practice.

1.12. Our analysis shows that there have been backwardation costs in each winter cap period and contango benefits in each summer period. Up to cap period seven, these have roughly netted off. Cap period seven is significantly different and represents a material departure from past cap periods.

1.13. Since backwardation costs and contango benefits roughly netted off in cap periods one through to six we consider it is appropriate to provide suppliers an allowance that reflects the extraordinary situation the market is currently in. To implement this, we believe it is appropriate to apply a deadband. The deadband sets an upper and lower limit where no allowance would be provided whereas costs outside the deadband would be recoverable.

1.14. We examined the following options to set this deadband:

- Mean +/- standard deviation: we calculated the average -£0.04 and standard deviation £16.10 of contango/backwardation impact observed in cap period one through six. To define the lower boundary of the deadband, we deducted standard deviation from the average value -£16.15. The upper boundary was set in a same way, summing standard deviation with the calculated average £16.06. Adopting this approach will provide suppliers the allowance to address additional backwardation costs.

- Historical minimum/maximum: we considered using the minimum and maximum values from period one through six to calculate the deadband range. This would mean taking the lowest observed value as the lower boundary, and the highest value for the upper boundary. However, we decided not to introduce such a deadband on the basis it would represent the worst-case scenario.

1.15. We chose the mean +/- standard deviation option because this approach will compensate efficient suppliers for the additional costs incurred in cap period seven compared to a normal expected outturn.

1.16. Six suppliers provided quantitative estimates of backwardation costs incurred in cap period seven, ranging from £16 to £35 per customer. One other supplier said these costs were zero. Each supplier describes the specific circumstances, methods, and rationale behind their cost estimates, which collectively reflect the different procurement and risk management practices in use across the industry. We think it is appropriate to use supplier estimates in places of our modelled value for the purpose of calculating the backwardation cost allowance.

1.17. To calculate the weighted average backwardation allowance for costs related to cap period seven, we used the number of SVT customer accounts as the weights. We applied the respective supplier weightings to each of the supplier estimates and then added the weighted estimates together to obtain the weighted average.

Shaping and imbalance costs

Supplier model review

1.18. Overall, eight suppliers provided estimates of increased shaping and imbalance costs for cap period seven.

1.19. One supplier included a model with volume and pricing data to build up their proposed shaping uplift for electricity. The model showed how they converted seasonal contracts to quarterly, monthly, and day-ahead. The overarching logic was similar to what we used in setting indexation levels, but the assumed hedging / pricing strategy was different to ours.

1.20. Two suppliers proposed allowance uplifts for various sub-components of shaping and imbalance for each fuel (eg imbalance cost, day-ahead re-hedging cost etc, quarterly to monthly shaping cost etc). We were able to use these uplifts to back-calculate an aggregated monetary impact for each fuel. One of these suppliers accompanied their proposed uplifts with significant contextual narrative, whilst the other did not.

1.21. Four suppliers provided high level estimated monetary impacts on a £/customer basis.

1.22. One supplier provided an estimated range in terms of monetary cost impact, which did not distinguish by fuel type.

1.23. It is worth noting that there was an overall lack of commentary from suppliers regarding increased shaping and imbalance costs pertaining to gas. Three suppliers provided estimates only for electricity, with either minimal or no commentary on gas. One supplier estimated that increased shaping and imbalance costs for gas (and electricity) was £0 and another supplier suggested there were in fact over-recovery from gas shaping and imbalance costs in cap period seven.

Methodological choices

1.24. We used supplier estimates of increased shaping and imbalance costs in cap period seven for calculating the weighted average increase on a £/customer basis.

1.25. Two suppliers provided a breakdown of increased per customer cost estimates by electricity and gas, and we were able to use those estimates directly in the weighted average calculation. Three suppliers provided an estimate for only electricity, and we assumed nil response for gas. Where the corresponding narrative indicated that items beyond the scope of the current methodology were included in the estimates, we did not take those items into consideration.

1.26. Two suppliers proposed allowance uplifts for various sub-categories within shaping and imbalance for each fuel. We only considered elements which directly mapped to the existing components within the shaping and imbalance allowance. For example, one supplier reported an uplift due to differences in assumed base to peak proportions, which was disregarded. For the categories which were comparable, we applied the proposed allowance uplifts to the respective electricity and gas direct fuel cost components for cap period seven.

1.27. For the one supplier that provided a total cost impact range (£ rather than £/customer), we took the median value of the range and applied a calculated gas cost to total cost ratio to obtain the electricity and gas split. We then divided the number by the supplier’s SVT customer account base for electricity and gas respectively to get the per customer increase.

1.28. The gas cost to total cost ratio used was calculated by looking at supplier estimates where a split between gas and electricity was available. We weighted these estimates by the suppliers’ respective SVT customer account base and then calculated gas cost as a percentage of total costs for each supplier. The average of these gas cost to total cost percentages gave us the gas cost to total cost ratio that was used to obtain the electricity and gas split for the supplier that provided a total cost range.

1.29. For the weighted average calculation, we used the number of SVT customers as the weights. This was taken from supplier data on default electricity and gas accounts as of 5 January 2022 from the Financial Responsibility Principle RFI. We applied the respective supplier weightings to each of the supplier estimates and then added the weighted estimates together to obtain the weighted average.

1.30. We calculated a separate weighted average for electricity and gas, using SVT customer accounts for electricity and gas respectively. Given that the majority of suppliers either provided only an estimate for electricity or estimated that for gas the additional cost was either zero or negative, we decided to make adjustments for electricity only. The resulting increased shaping and imbalance costs for cap period seven with respect to electricity is £11.54.

Other supporting analysis

1.31. The shaping and imbalance indexation levels that have been applicable since the first price cap period were calculated in 2018.

1.32. We re-ran the original analysis performed to set the shaping and imbalance indexation levels, which involved holding the existing methodology constant and extending all input datasets. This has given us a view on how the indexation levels would have evolved over time if set at each cap period. In cap period seven, our results show over-recovery in gas driven by opportunities to sell volumes at higher prices, and under-recovery for electricity.

Appendix 2: Glossary

Term	Description
6-2-6 methodology	The 6-2-6 semi-annual approach refers to an approach to calculate the weighted average cost of energy. It uses a six-month observation window which ends two months prior to the start of the cap period and observes a 6-month period of forward electricity and gas contracts.
6-2-12 methodology	The 6-2-12 semi-annual approach refers to how we calculate the weighted average cost of energy. It uses a six-month observation window which ends two months prior to the start of the cap period and observes a 12-month period of forward electricity and gas contracts.
Backwardation and contango, and basis risk	The price cap is based on an annual price (of gas and electricity for 12 months) but updated every six months. The price cap level is set using forward prices. Put very simply, the 12-month annual price level is set using forward contract prices for across the 12 months. This is done to reduce seasonal fluctuations in price. This creates 'basis risk' where suppliers over-recover costs in summer and under-recover in winter. Normally the differences in the prices for winter and summer, combined with the increased demand in winter means that this nets out – ie that suppliers are able to recover the full costs in a reasonable period of time. When the market is in backwardation the forward prices in the later six months are lower than in the first six (the actual price cap period). It brings the price cap level below the cost to suppliers of purchasing that energy for consumers (for that price cap period). Contango is the opposite of backwardation, when the forward market prices for near-term contracts are lower than prices further in the future, a situation which delivers modest gains to suppliers. When we first set the price cap, we assumed that the costs of backwardation and benefits of contango would roughly net off in the long run. And, from 2019 until summer 2021, this was the case.

Balancing Services Use of System (BSUoS) charges	The Balancing Services Use of System (BSUoS) charges recover the costs of the balancing actions taken by the ESO when undertaking the day-to-day operation of the National Electricity Transmission System. Generators and suppliers are liable for these charges, which are calculated daily as a flat tariff across all users.
Capacity Market (CM)	The Capacity Market (CM) provides a regular retainer payment to reliable forms of capacity (both demand and supply side), in return for such capacity being available when the system requires it.
Capture Price Cost	Capture price is the generation-weighted average (GWA) price received by a technology or an asset. It can be higher or lower than the time-weighted average price (TWA or Baseload price).
Contracts for Difference (CfD)	CfD contracts off a guaranteed income level for eligible generation which bid for these contracts in a competitive process overseen by the Low Carbon Contracts Company (LCCC).
Deadband	A 'deadband' in this document refers to an approach to quantify what a normal range of costs would be. We use a deadband in this decision to estimate the 'normal' basis spreads suppliers would have experienced during cap period seven.
Direct Fuel Allowance (Additional)	We uplift the core direct fuel allowance by a set percentage to reflect the expected costs of converting less granular forward contracts to more granular demand before delivery, transaction costs, losses and additional uncertainty.
Direct Fuel Allowance (Core)	We estimate the significant majority of wholesale costs based on forward contracts for electricity and gas, using an updated version of the Competition and Markets Authority's (CMA) prepayment meter (PPM) cap wholesale market model.
Distribution Use of System Charges (DUoS)	Distribution Use of System Charges (DUoS) cover the cost of operating and maintaining a safe and reliable electricity infrastructure between the transmission system and end users such as homes and businesses. The electricity infrastructure includes overhead lines, underground cables, as well as substations and transformers.
Energy Company Obligation Scheme (ECO)	The Energy Company Obligation Scheme (ECO) is a programme to deliver energy efficiency measures in homes across Great Britain. ECO4 covers the period 1 April 2022 to 31 March 2026
Headroom	An additional component which 'tops-up' the cap to ensure due regard is given to the net cost of residual risk and uncertainty not already compensated by Ofgem's efficient cost estimates.

Interim Levy Rate (ILR)	An Interim Levy Rate (ILR), which is determined by the Low Carbon Contracts Company (LCCC) by reference to forecasts (of demand, generation, market prices, weather, etc.), and paid daily by suppliers on a £ per MWh supplied basis. It is intended to cover payments to CfD generators over a given calendar quarter (known as the 'rate period').
Price Cap Periods	Cap period six – 1 April 2021 to 30 September 2021 Cap period seven – 1 October 2021 to 31 March 2022 Cap period eight – 1 April 2022 to 30 September 2022 Cap period nine – 1 October 2022 to 31 March 2023
Transmission Network Use of System Charges (TNUoS)	Transmission Network Use of System Charges (TNUoS) recover the Transmission Owner's allowed revenues under the price control settlements and are charged to both demand users and generators. They are broadly separated into forward-looking charges, which relate to the incremental cost of using the network in a specific location, and residual charges that recover the remaining costs and are non-locational.
Unidentified Gas (UIG)	Unidentified Gas is gas supplied to the network that cannot be directly attributed to a gas shipper. It is the shortfall between the volume of gas that enters the National Grid and that which is measured as consumed by customer meters.
Wholesale Additional Risk Allowance	Included within the cap methodology to account for uncertainty and volatility in wholesale costs, beyond what is already provided for in the other wholesale allowances and headroom.