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Consultation

CMP308 – Minded-to decision and draft impact assessment			
Publication date:	08 December 2021	**Contact:**	Ruben Pereira, Policy Manager
		Team:	Electricity Network Charging
Response deadline:	19 January 2022	**Tel:**	020 7901 7000
		Email:	ElectricityNetworkCharging@ofgem.gov.uk

We are consulting on our minded-to decision on a proposed change to the way that the Balancing Services Use of System (BSUoS) charges are collected from electricity network users. In 2020, the second BSUoS Task Force recommended that BSUoS charges be recovered only from Final Demand.[1] The CUSC (Connection and Use of Systems Code) modification CMP308[2], if approved, would implement this recommendation. We would like views from people with an interest in electricity network charging. We particularly welcome responses from electricity generators, suppliers and other users of the GB electricity networks. We also welcome responses from other stakeholders and the public.

This document outlines the scope, purpose and questions of the consultation and how you can get involved. Once the consultation is closed, we will consider all responses. We want to be transparent in our consultations. We will publish the non-confidential responses we receive alongside a decision on next steps on our website at **Ofgem.gov.uk/consultations**. If you want your response – in whole or in part – to be considered confidential, please tell us in your

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1 second-balancing-services-charges-task-force-final-report.pdf (chargingfutures.com)
2 CMP308 Wider System and Distributional Impacts of Recovering Balancing Services Costs from Demand FINAL STC 30h0621 (ofgem.gov.uk)

response and explain why. Please clearly mark the parts of your response that you consider to be confidential, and if possible, put the confidential material in separate appendices to your response.

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Executive summary

In November 2019, we published our Decision on the Targeted Charging Review (TCR) Significant Code Review.[3] The TCR aimed to ensure the costs of operating, maintaining and upgrading the electricity grid would be spread more fairly across users, with fewer distortions. The TCR included a review of how residual network charges are set and recovered, and also sought to remove some remaining distortions in network charging, known as Embedded Benefits.[4]

Balancing Services Use of System (BSUoS) charges are the means by which the Electricity System Operator ('ESO') recovers costs associated with balancing the electricity transmission system. Currently, these charges are recovered using a charge that varies for each half hour, and GB is relatively unusual compared to other countries in Europe in that these charges are recovered equally from demand and generation. The TCR removed an Embedded Benefit associated with BSUoS[5] and noted that the differences in arrangements between Small Distributed Generators[6] and Large Generators amounted to a distortion, but did not make changes to BSUoS itself. Instead, the TCR launched two industry Task Forces to look at the costs recovered by BSUoS, who should be liable for the charges, and how these charges should be recovered.

The Task Forces made various recommendations as to how BSUoS charges should be set and recovered, including a recommendation that BSUoS costs be recovered solely from Final Demand. CMP308 is the modification which would implement this change. The Task Force also recommended that BSUoS charges take the form of a flat volumetric charge, set in advance. Other CUSC modifications, CMP361 and CMP362, cover that change.

This consultation focuses on the move of BSUoS from generation to demand. Our consultants' modelling suggests the proposed changes could benefit energy consumers by £320m in the period to 2040, assuming a Net Zero[7] compliant scenario. By reducing distortions in the generation sector, CMP308 would also see GB energy system costs (excluding non-priced

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[3] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-decision-and-impact-assessment
[4] Embedded Benefits is the name given to the differences in charging arrangements between Small Distributed Generators and large generators (with capacity >100MW) connected to either the distribution or transmission networks.
[5] This was implemented via CMP333 '*Connection and Use of System Code (CUSC) CMP333: BSUoS – charging Supplier Users on gross demand (TCR)'* which Ofgem approved on 3 December 2020: cmp333_final_version_031220 (1).pdf
[6] Small distribution connected generators with capacity less than 100MW are currently treated differently from Large generators, whether connected to the transmission or distribution networks.
[7] In June 2019 the UK government set into law the requirement to end its contribution to global warming by 2050, bringing all greenhouse gas emissions to Net Zero.

carbon impacts) reduced by around £400m as a result of more efficient dispatch and investment. Our modelling suggests that flows on interconnectors, which do not currently face BSUoS charges, would change as a result of this proposed change, and that there will be significant differences to GB generation investments. When emissions reductions in other territories are considered, overall CO_2[8] emissions are expected to fall. Those from the GB energy system would go up, but emissions would fall by a greater amount in interconnected markets. We estimate that when considering the net impact of these carbon emissions, our core scenario leads to benefits to society in the order of £810m in the period out to 2040[9].

Major changes to our energy system are required to deliver the Net Zero transition, with efficient investment needed in generation. We consider that well-functioning markets free from distortions are vital for the investment and flexibility needed to facilitate Net Zero at least cost, and that this proposal is likely to improve price signals and ensure cost recovery happens on a more efficient basis.

Based on our assessment, we are minded-to approve the CMP308 Original Proposal, which would move BSUoS charges fully onto demand with effect from 1 April 2023. We consider the Original Proposal will better facilitate the achievement of the Applicable CUSC Charging Objectives (ACOs) and be consistent with our principal objective and statutory duties. We are seeking views on our assessment against the ACOs and our duties, and the reasoning, modelling and impacts we have produced to support this work. The closing date for responses is 19 January 2022.

[8] CO_2 (Carbon Dioxide) emissions are a by-product of fossil fuel combustion and are the principal greenhouse gas contributing to climate change.

[9] Our assessment found that counting GB emissions changes alone – which may not reflect the global nature of carbon emissions - would lead to an incremental £1.1bn wider system cost using BEIS carbon appraisal values. This is because while this modification leads to an increase in emissions associated with GB that are produced within GB borders, it leads to a reduction of emissions associated with GB that are produced elsewhere. This leads to a reduction in emissions that are associated with GB overall.

1. Background

Section summary

We describe the background to this proposal, including the existing BSUoS charges and their impact on the market, the TCR, the BSUoS Task Forces and previous modifications in this area.

BSUoS Charging

1.1. BSUoS charges are the means by which the Electricity System Operator ('ESO' or 'NGESO') recovers costs associated with balancing the electricity transmission system. They recover several categories of costs[10], including:

- the costs of constraints;
- the costs of frequency response services;
- the costs of reserve provision;
- the costs associated with Balancing Mechanism actions; and
- the ESO's internal costs.

1.2. BSUoS charges are currently recovered using a volumetric charge (£/MWh) from both demand customers and liable generators based on the amount of energy imported from or exported onto the network within each half-hour period.

1.3. Generators liable for BSUoS are those connected to the transmission system and distributed generation with capacity of 100MW or greater, otherwise known as 'Large Distributed Generation' or 'Large DG'. Such generators are collectively referred to as 'Large Generators' in this document. Charges are levied on Large Generators based on their energy exports and imports, while transmission-connected and large[11] distribution-connected storage

[10] Balancing Services Use of System (BSUoS) charges | National Grid ESO
[11] 100MW and above.

users pay BSUoS charges only on their exports. Charges are levied on suppliers in relation to their gross energy imports. Interconnector Balancing Mechanism Units and smaller distributed (<100MW) generators and storage do not face the charge[12].

1.4. The potential for broad reform to BSUoS charges has long been discussed, in particular due to the differential treatment between Large Generators and other generation. In addition, BSUoS has been recognised as providing signals to users that do not encourage efficient responses and may in some cases, send counter-intuitive signals.

The BSUoS Task Force

1.5. In November 2019, we published our Decision (and associated Directions) on the Targeted Charging Review (TCR) Significant Code Review.[13] The TCR included a review of how residual and cost-recovery network charges are set and recovered, in particular establishing non-cost reflective charges should be recovered from Final Demand in a non-distortive manner.[14] Our work on TCR removed some distortions, including the removal of an Embedded Benefit[15] associated with BSUoS, but stopped short of making changes to BSUoS itself. Our November 2018 TCR minded-to decision[16] launched the first BSUoS Task Force[17], which was asked to examine whether and how the cost reflectivity of BSUoS could be improved to provide better forward-looking signals.

1.6. The first Task Force concluded BSUoS "does not currently provide any useful forward-looking signal" and that it should be treated as a cost-recovery charge.[18] When we published our TCR Decision, we acknowledged the conclusion of the first Task Force, and asked the ESO to launch a further industry working group[19] (the second BSUoS Task Force) to assess who should be liable for BSUoS charges and how these charges should be recovered.

[12] Storage users may pay toward the generation share of BSUoS charges through their purchases of wholesale of electricity, for which the generator may be liable for BSUoS charges.
[13] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-decision-and-impact-assessment
[14] The TCR aimed to ensure that residual charges are recovered from network users in a way that balanced the need to reduce harmful distortions, maintain fairness, and charge in a way that is practical and proportionate.
[15] Our TCR Decision directed that the ability for suppliers to reduce their liability for BSUoS charges by contracting with distributed generators with capacity less than 100 MW should be removed. This was achieved by recovering BSUoS charges for demand on a gross consumption basis, rather than a net consumption basis at the point the transmission network meets the distribution network. The modification that enacted this change, CMP333, was approved by Ofgem in December 2020 and implemented in April 2021.
[16] https://www.ofgem.gov.uk/sites/default/files/docs/2018/11/targeted_charging_review_minded_to_decision_and_draft_impact_assessment.pdf
[17] Review of balancing services charges (ofgem.gov.uk)
[18] ESO Word Template - Full Width (chargingfutures.com)
[19] Launch of a second Balancing Services Charges Taskforce (ofgem.gov.uk)

1.7. This second Task Force recommended[20] that BSUoS be paid solely by Final Demand, and also that it should be levied in the form of a flat volumetric £/MWh charge that was known to users in advance and was of a fixed level, not varying throughout the charging year. [21]

1.8. The key reasons for their conclusions that BSUoS should be paid solely by Final Demand were that:

- Levying BSUoS charges on Final Demand only would reduce distortions between Large Generators who are currently liable for BSUoS charges and interconnectors and other forms of generation, in particular Small Distributed Generators who are not.

- Expanding the charge base to include distributed generation (in an attempt to address the existing distortion between Large Generators and other generators not liable for BSUoS charges) would create a new distortion between network-connected and on-site generation, which could be avoided[22] by charging BSUoS solely to Final Demand.

- Given BSUoS charges are cost recovery charges, it is not efficient to recover part of it via generation, because doing so means the costs are passed through into retail and wholesale costs, which includes unnecessary risk premium and transaction costs.

1.9. CMP361 and CMP362[23] are the modification proposals, which would, if approved, implement the remainder of the second Task Force's findings. This was that BSUoS charges, which are currently variable, should be set to a flat volumetric charge on an ex-ante basis.[24]

[20] second-balancing-services-charges-task-force-final-report.pdf (chargingfutures.com)
[21] Currently BSUoS charges are recovered using a £/MWh volumetric charge that varies in cost in each 30 minute settlement period to reflect the specific costs that arose in that period.
[22] It should be noted that collecting BSUoS charges wholly from Final Demand as a volume charge increases the potential benefit gained from avoiding demand BSUoS charges using on-site generation.
[23] CMP361 & CMP362 'BSUoS Reform: Introduction of an ex ante fixed BSUoS tariff & Consequential Definition Updates' | National Grid ESO
[24] It should be noted that in 2015 a modification, CMP250, was raised to fix BSUoS charges into a flat volumetric charge. We rejected CMP250 in 2018, before the establishment and findings of the first and second BSUoS Task Forces, and so before the first Task Force had established BSUoS charges were cost recovery charges. At the time, we did not consider that the evidence provided in the final modification report was sufficient to allow us to determine whether the solutions presented would have had a positive or negative impact on the relevant charging ACOs, and we were not satisfied that a case had been made that the proposed changes facilitated more effective competition. Ofgem's decision is available here.

These modification proposals also concern the arrangements that would allow the ESO to manage the additional tasks of forecasting such a charge and managing risks and cash flows.

1.10. In December 2020, we published an open letter that supported the second Task Force's recommendations in principle, whilst recognising that quantitative analysis as to the overall impacts of the reforms would be required to inform a final decision.[25] Ofgem committed to carry out this quantitative work. In February 2021, we issued an invitation to tender and, following a competitive process, commissioned Frontier Economics and Lane Clark & Peacock (LCP) to carry out this work. We published their assessment of the impacts of recovering BSUoS charges from Final Demand alongside an open letter in July 2021, which ensured that the estimated magnitude and direction of impacts of the modification were available to the CMP308 Workgroup prior to the Code Administrator Consultation stage.[26] That Frontier-LCP work, alongside our assessment of the modifications against the relevant ACOs and our duties, forms the basis of this consultation. A supplement to the initial work which examines the impact of new BEIS carbon values on the results of the wider system analysis is published as a subsidiary document and considered in our findings.[27]

CMP308

1.11. Following the second BSUoS Task Force's recommendations, we set out our expectations that industry would develop solutions to modify the relevant industry code (the Connection and Use of System Code ('CUSC'), which covers the charging provisions for BSUoS charges) in line with the Task Force recommendations through the code modification process. In this instance, it was not necessary for an industry party to raise a new code modification proposal as an existing modification, CMP308, was considered an appropriate way to give effect to the terms of the Task Force outputs with regards moving liability for BSUoS charges solely to Final Demand.

1.12. The proposer of CMP308, which was raised prior to the second Task Force's findings, looked to resolve a defect they had identified relating to differences in the costs that certain GB generators are currently liable for when compared to generators in EU countries. The proposer argued that these differences amounted to a distortion in the generation sector which,

[25] Ofgem response to publication of the final report of the second Balancing Services Use of System (BSUoS) Task Force
[26] Open Letter and CMP308 Wider System and Distributional Impacts of Recovering Balancing Services Costs from Demand FINAL STC 300621 (ofgem.gov.uk)
[27] LCP modelling - BSUoS wider system modelling with updated Carbon Appraisal Values for Ofgem

if corrected, would allow better competition between GB generation and their EU equivalents, with whom they compete. In their view, the removal of BSUoS charges from GB generators would better align the GB 'generation cost stack' with the costs faced by EU generators and would deliver more effective competition. This, in turn, would benefit end consumers, by ensuring generation dispatch and investment in new generation is more efficient than under the *status quo* arrangements[28]. In seeking to transfer the proportion of BSUoS charges currently paid by generation to demand users, CMP308 would deliver a key recommendation of the second Balancing Services Charges Task Force that BSUoS charges should be paid by Final Demand[29].

Previous similar proposals

1.13. In 2011, a CUSC modification, CMP201[30], was raised which sought to move BSUoS charges wholly onto Final Demand. We rejected this proposal in 2014, whilst noting that "we support the fundamental economic principle that increasing competition should lead to lower wholesale prices in the long run". In our reasons for rejection, we stated that we were "concerned that at this time the potential benefits […] would not be material enough to offset the potential costs to consumers from implementing the modification". We consider there to have been significant changes to the energy system since this decision, and also that the more recent analysis that we commissioned to inform our decision on CMP308 supplants that carried out for CMP201.

Wider context

1.14. Major changes to our energy system are required to deliver the Net Zero transition, with efficient investment needed in generation. We consider that well-functioning markets free from distortions are vital for the investment and flexibility needed to facilitate Net Zero at least cost, and that this proposal is likely to improve price signals and ensure cost recovery happens on a more efficient basis. Other key work aligned to these goals includes our Access and Forward

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[28] More efficient investment might mean the most efficient plant in the optimal location being built, or the least competitive plant closing first. More efficient dispatch should see the lowest cost generation running before other plant a greater proportion of the time.
[29] The proposer was primarily motivated to raise CMP308 to address perceived competition distortions between GB generation and its EU counterparts. The second Task Force had further reasons to support charging to Final Demand beyond this issue, as set out above.
[30] CMP201- Removal of BSUoS Charges from Generators | National Grid ESO

Looking Charges SCR[31] and our ongoing work on Full Chain Flexibility[32], which builds on the existing work that we set out with BEIS in the 2021 Smart Systems and Flexibility Plan[33] and its preceding work[34].

1.15. Key to delivering flexibility and efficient investment is ensuring that network users are in a position to respond to appropriate price signals, and that the most efficient or cost-effective providers of power or system services are used at any given time. Efficient generation dispatch occurs when the least expensive generation is brought online before more expensive generation. This concept is known as the "merit order" and is fundamental in competitive generation markets.

1.16. Price signals that are currently sent to generators through BSUoS charges are not cost-reflective and may lead to generation being dispatched "out of merit", where more expensive generation is brought into the market before less expensive generation. An example of this might be where one generator appears cheaper due to differences in BSUoS charges paid versus another source of generation. Reducing distortions to efficient price signals is therefore in the interest of consumers, as it removes barriers to competition and brings the lowest cost generators into the market first. The efficient dispatch of generation also has the potential to reduce wholesale costs, and through improvements to market functioning, has the potential to reduce the lifetime cost of generation investment across all technologies. Together, where achieved, these effects are likely to deliver lower costs for consumers.

[31] In December 2018, we launched a Significant Code Review (SCR) into electricity network access and forward-looking charging. The objective of the SCR is to ensure that electricity networks are used efficiently and flexibly, reflecting users' needs and allowing consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general. Our most recent publication on this SCR consulted on minded-to positions across a number of Access subject areas https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[32] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/full-chain-flexibility
[33] https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021
[34] https://www.gov.uk/government/publications/upgrading-our-energy-system-smart-systems-and-flexibility-plan

2. This consultation

Section summary

We describe the aims and processes of this consultation and the legal and regulatory framework that underpins it. We set out the timelines and privacy and data provisions of the consultation. We also summarise the questions and provide a summary of our minded-to position.

What are we consulting on?

2.1. This consultation focuses on our minded-to decision on CMP308, and specifically on whether to direct that the modification be made as no alternative proposals have been presented alongside CMP308. This consultation focuses on the following assessment areas:

- Assessment against Applicable Code Objectives (ACOs) and our statutory duties;
- Assessments of costs and benefits, both monetised and non-monetised; and
- Distributional impacts

2.2. Through the work of the BSUoS Task Forces, and during the industry processes relating to CMP308, there were a number of consultations where stakeholders could provide their views, including the Workgroup and Code Administrator Consultations. As noted above, we also shared our consultants' reports on the costs and benefits of this proposal in July 2021 prior to the Code Administrator Consultation. Due to the variable nature of BSUoS charges, exact assessment of the distributional impacts of the options is not possible, but we have undertaken distributional modelling and wider systems modelling to quantify and support our assessment of the likely effects of this modification.

Our minded-to decision

2.3. We are minded-to direct that modification CMP308 be made, with an implementation date of 1 April 2023.

2.4. We are seeking responses on a number of questions to inform our final decision. These questions are presented throughout this document alongside the relevant discussion and are also presented below.

Questions

1. Do you agree with our assessment that CMP308 better facilitates the Applicable CUSC Objectives?
2. Do you agree that charging BSUoS charges only to Final Demand reduces distortions between Large Generators and other forms of generation? Please explain why.
3. Do you have any views on the impact of this proposal on Behind The Meter Generation and its competitiveness?
4. Do you have any views on our reasoning on this proposal's effect on price signals or generation dispatch?
5. Do you have any views on our reasoning on this proposal's effect on competition between different generator types?
6. Do you have views on our assessment of the decarbonisation impacts of this proposal, both in respect of emissions from the GB energy system and of overall emissions?
7. Do you have views on whether and the extent to which the changes proposed in this modification have already been incorporated into supplier decisions?
8. Do you have views on the impact of this proposal on existing supply contracts, including the possibility of costs or delayed benefits to consumers stemming from windfall gains to industry parties, or double payments?
9. Do you have views on this proposal's impacts on generator and supplier risks, including on exposure to volatile charges?
10. Do you have views on the interactions between this proposal and other changes in the sector, including other BSUoS charging reform proposals?
11. Do you have views on the modelled assessment of consumer and energy system benefits? Please provide quantitative analysis and any further information.
12. Is our assessment of non-monetised costs and benefits reasonable? Are there any other factors we should consider?
13. Do you consider the consumer and system benefits identified in our consultants' modelling to represent a reasonable view of the potential effects of this modification?
14. Do you consider that Ofgem has duly considered all relevant consumer and system benefits? Are there any areas which could benefit from further analysis?
15. Our modelling assumes that CfD adjustment payments designed to compensate contract holders for the BSUoS charges they face will no longer be paid in the event generation is not liable for BSUoS charges. Do you agree with this assumption, and do you have views on our assessment of the risks associated with existing CfD contracts?
16. Do you have views on the impacts of this proposal on end consumers, including large users and vulnerable users?

17. Do you agree with our assessment that reduced costs to generators are likely to feed through into lower wholesale prices?
18. Do you agree with our assessment that this policy will not have any significant material impacts on vulnerable users?
19. Do you agree with our assessment that this modification is unlikely to lead to any significant impacts on essential services or supply chains?
20. We would note that increases in demand costs will need to be incorporated into the Price Cap methodology. Do you have any views on this area?
21. Do you agree with our proposed implementation date of 1 April 2023? Please provide your reasoning.
22. Do you have any other information which is relevant to this consultation?

Related modifications

2.5. We note that there are a number of other modifications that interact with this modification or are closely linked. These are:

- P419 - *Enhanced Reporting of Demand Data to the ESO to facilitate BSUoS Reform*[35] - seeks to enable exclusion of non-Final Demand from BSUoS charges
- CMP377 - *Clarification of Section 14 BSUoS Charging Methodology*[36] – among other things, clarifies BSUoS charging methodology.
- CMP361/2 - *BSUoS Reform: Introduction of an ex ante fixed BSUoS tariff & Consequential Definition Updates*[37] - seeks to introduce an ex ante fixed volumetric BSUoS charging tariff.

2.6. For the avoidance of doubt, this minded-to decision does not cover the aforementioned modifications.

[35] P419 'Enhanced Reporting of Demand Data to the NETSO to facilitate BSUoS Reform' - Elexon BSC
[36] CMP377 'Clarification of Section 14 BSUoS Charging Methodology' | National Grid ESO
[37] CMP361 & CMP362 'BSUoS Reform: Introduction of an ex ante fixed BSUoS tariff & Consequential Definition Updates' | National Grid ESO

Our impact assessment

2.7. Where appropriate, regulatory proposals are accompanied by impact assessments (IAs) which assess and estimate the likely associated risks, costs and benefits that have an impact on business, individuals and the environment.

2.8. Section 5A[38] of the Utilities Act 2000 imposes a duty on the Authority (its 'Section 5A duty') to undertake an impact assessment in certain circumstances. In particular, that applies where it appears to the Authority that a proposal is important. A proposal is important for these purposes if its implementation would be likely to, among other things, "have a significant impact on persons engaged in commercial activities connected with the […] generation, transmission, distribution or supply of electricity." Where this applies, the Authority is obliged to carry out an impact assessment. We consider that this impact assessment, which we have carried out in line with our impact assessment guidance[39], meets our obligations under the Utilities Act in a proportionate, consistent and transparent manner.

2.9. Our TCR Decision ("TCR IA") did not look at the impact of moving BSUoS charges from generation to demand, as this recommendation stems from the BSUoS Task Force work. This impact assessment looks at those impacts and is informed by our consultants' modelling, which was previously published on our website[40] and is now supplemented with further information[41]. We refer to this modelling within this document as "our consultants' modelling" or "the modelling" to aid understanding, and to draw a distinction between other analysis and assessments we have carried out.

2.10. In producing the modelling, our consultants had to make a range of simplifications and assumptions. The user groups were designed to represent a reasonable spread of different levels and shapes of consumption, but they were not representative of all consumers. As a result, the charges and bill impacts estimated were illustrative to provide an indication of the expected impacts.

2.11. To aid navigation and improve readability, we have integrated the impact assessment within this consultation document, as opposed to producing a separate IA document. We

[38] https://www.legislation.gov.uk/ukpga/2000/27/section/5A
[39] https://www.ofgem.gov.uk/publications/impact-assessment-guidance
[40] CMP308 Wider System and Distributional Impacts of Recovering Balancing Services Costs from Demand FINAL STC 300621 (ofgem.gov.uk)
[41] LCP modelling - BSUoS wider system modelling with updated Carbon Appraisal Values for Ofgem

consider this IA to be within scope of Public Sector Equality Duties[42] and consider this to be a non-qualifying measure for the Business Impact Target.

Consultation stages

2.12. The consultation period will close on 19 January 2022. We note that the modelling that supports this consultation has been available to industry since July 2021.

2.13. Following this consultation, we will assess responses and consider whether any further analysis or engagement is required before publishing a decision on CMP308. We will publish separate decisions relating to the linked modification proposals referred to above.

How to respond

2.14. We want to hear from anyone interested in this consultation. Please send your response to the person or team named on this document's front page.

2.15. We have asked for your feedback in each of the questions throughout. Please respond to each one as fully as you can.

2.16. We will publish non-confidential responses on our website at www.ofgem.gov.uk/consultations.

Your response, data and confidentiality

2.17. You can ask us to keep your response, or parts of your response, confidential. We will respect this, subject to obligations to disclose information, for example, under the Freedom of Information Act 2000, the Environmental Information Regulations 2004, statutory directions, court orders, government regulations or where you give us explicit permission to disclose. If

[42] In broad terms, the duties set out in S.149 of the Equality Act 2010 require a public authority to have regard to a number of provisions that advance equality and avoid harms toward and between individuals with a range of protected characteristics. There are some overlaps between these duties and our statutory duties as set out in other legislation. The Small Business, Enterprise and Employment Act 2015 (SBEE Act 2015) creates a legal obligation on the Government to publish a Business Impact Target, and regulators are required to transparently report on the cost to business of qualifying changes to their regulatory policies and practices.

you do want us to keep your response confidential, please clearly mark this on your response and explain why.

2.18. If you wish us to keep part of your response confidential, please clearly mark those parts of your response that you *do* wish to be kept confidential and those that you *do not* wish to be kept confidential. Please put the confidential material in a separate appendix to your response. If necessary, we will get in touch with you to discuss which parts of the information in your response should be kept confidential, and which can be published. We might ask for reasons why.

2.19. If the information you give in your response contains personal data under the General Data Protection Regulation (Regulation (EU) 2016/679) as retained in domestic law following the UK's withdrawal from the European Union ("UK GDPR"), the Gas and Electricity Markets Authority will be the data controller for the purposes of GDPR. Ofgem uses the information in responses in performing its statutory functions and in accordance with section 105 of the Utilities Act 2000. Please refer to our Privacy Notice on consultations, see Appendix 1.

2.20. If you wish to respond confidentially, we will keep your response itself confidential, but we will publish the number (but not the names) of confidential responses we receive. We won't link responses to respondents if we publish a summary of responses, and we will evaluate each response on its own merits without undermining your right to confidentiality.

General feedback

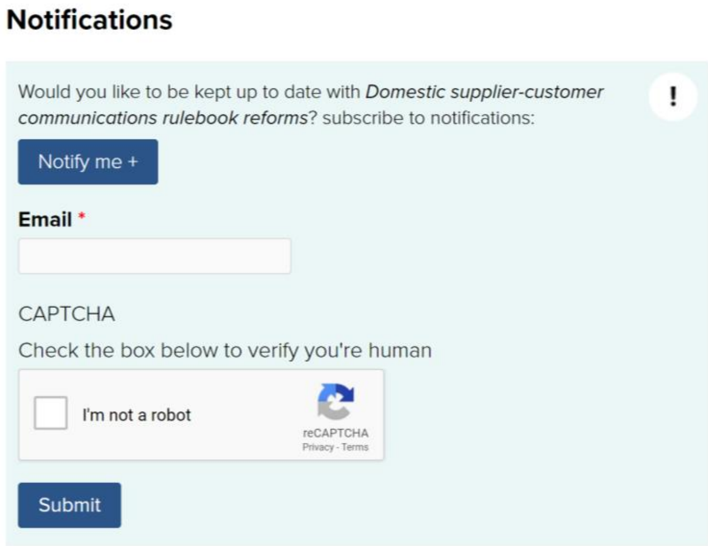
2.21. We believe that consultation is at the heart of good policy development. We welcome any comments about how we have run this consultation. We would also like to get your answers to these questions:

1. Do you have any comments about the overall process of this consultation?
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. Were its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

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

How to track the progress of the consultation

You can track the progress of a consultation from upcoming to decision status using the ‘notify me’ function on a consultation page when published on our website. [Ofgem.gov.uk/consultations.](https://www.ofgem.gov.uk/consultations)



Once subscribed to the notifications for a particular consultation, you will receive an email to notify you when it has changed status. Our consultation stages are:

Upcoming → Open → Closed (awaiting decision) → Closed (with decision)

3. The modification proposal and CUSC Panel assessment

Section summary

We describe the modification proposal for CMP308. We outline the process that led to the raising of this modification and the votes of the CUSC Panel. The CUSC Panel voted in support of this modification being better than the existing provisions (baseline).

The modification proposal

3.1. CMP308 is a single proposal, with no Workgroup Alternative CUSC Modifications (WACMs), which would move BSUoS charging liability solely to Final Demand[43].

3.2. EDF Energy raised CMP308 in 2018 aiming to address perceived distortions in the generation market brought about by differences in BSUoS charge liability between domestic Large Generators and the EU generation with which it competes.

3.3. We wrote to the CUSC Panel Chair in November 2018 suggesting work on CMP308 be discontinued until the work of the Task Force work was complete.[44] The modification was in fact not paused due to support from some, but not all, CUSC Panel members.

3.4. Following the second BSUoS Task Force conclusions, the Workgroup felt that CMP308 was an effective way to enact the Task Force recommendations that BSUoS charges be levied on Final Demand only. The decision was taken not to combine the work on CMP308 with CMP361 which seeks to deliver the remainder of the Task Force recommendations. This was due to perceived benefits from having separate decisions, particularly in potentially providing earlier notice of change to industry.

3.5. A second Workgroup Consultation was run in April 2021 to ensure new information raised by the second Task Force report could be commented on. Broadly, the Workgroup was supportive of the modification, and mostly supportive of the 2023 implementation timescales, though some members felt later implementation necessary.

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[43] The concept of Final Demand has previously been defined in CMP334 WACM1 which we approved in November 2020.
[44] cmp308_letter_on_continuation_of_the_mod.pdf

3.6. The Code Administrator Consultation was carried out in August 2021, and once again the proposal received broad support. Some concerns were raised around its impacts on the price cap methodology, as well as concerns that it presented the possibility of windfall gains for generators, depending on implementation timescales.

CUSC Panel recommendation

3.7. The CUSC Panel met and voted on CMP308 in September 2021, agreeing unanimously that it better facilitated the ACOs[45] than the baseline[46]. Panel members suggested that the change would improve cost reflectivity of price signals and accepted Ofgem's consultants' report on the benefits. Some members did suggest Ofgem should continue to monitor whether the reductions in charges for generators would be matched by corresponding falls in the wholesale price of power, such that consumers were not disadvantaged overall. Panel members also suggested this modification would be successful in removing distortions between different types of generators and improve the efficiency of cost recovery.

3.8. The ACOs are present below, and our assessment against them is detailed in full in section 4 below:

a) Facilitating effective competition

that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity

b) Cost-reflective charging

that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred

[45] As set out in Standard Condition C5(5) of NGESO's Transmission Licence, see: https://epr.ofgem.gov.uk//Content/Documents/Electricity%20transmission%20full%20set%20of%20consolidated%20standard%20licence%20conditions%20-%20Current%20Version.pdf

[46] The status quo arrangements under the CUSC.

by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection)

c) Taking account of the developments of transmission licensees' businesses

that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses

d) Compliance with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency for the Cooperation of Energy Regulators

e) Promoting efficiency in the implementation and administration of the charging methodology

3.9. The CUSC Panel considerations on each ACO are summarised below. In summary, the majority of the panel considered that ACOs (a) and (e) were better than the baseline. We discuss our own assessment against the ACOs in section 4 of this document, and present the ACOs in full.

Table 1 - CUSC Panel voting

Option	Best Option?	ACOs better facilitated				
		a)	b)	c)	d)	e)
CMP308 Original	9 Votes	9 Votes	2 Votes	1 Vote	2 Votes	6 Votes

4. Our assessment and minded-to decision

Section summary

We are minded-to approve the CMP308 Original Proposal and consider that implementation should take place in April 2023. In our assessment of the options, we find CMP308 to better facilitate the achievement of the Applicable CUSC Charging Objectives and be consistent with our principal objective and statutory duties. We present some key impacts of CMP308 and seek views on our minded-to decision.

Questions

1. Do you agree with our assessment that CMP308 better facilitates the Applicable CUSC objectives?
2. Do you agree that charging BSUoS charges only to Final Demand reduces distortions between Large generation and other forms of generation? Please explain why.
3. Do you have any views on the impact of this proposal on Behind The Meter Generation and its competitiveness?
4. Do you have any views on our reasoning on this proposal's effect on price signals or generation dispatch?
5. Do you have any views on our reasoning on this proposal's effect on competition between different generator types?
6. Do you have views on our assessment of the decarbonisation impacts of this proposal, both in respect of emissions from GB energy system and of overall emissions?
7. Do you have views on whether and the extent to which the changes proposed in this modification have already been incorporated into supplier decisions?
8. Do you have views on the impact of this proposal on existing supply contracts, including the possibility of costs or delayed benefits to consumers stemming from windfall gains to industry parties, or double payments?
9. Do you have views on this proposal's impacts on generator and supplier risks, including on exposure to volatile charges?
10. Do you have views on the interactions between this proposal and other changes in the sector, including other BSUoS charging reform proposals?

Legal and regulatory assessment framework

4.1. We have evaluated this proposal on a holistic basis, taking into account our understanding of the potential impact on consumers, as well as different categories of market participants. The modification has been assessed against (i) the ACOs and (ii) our Principal Objective of protecting the interests of existing and future energy consumers wherever appropriate by promoting effective competition[47], and our other statutory duties.

4.2. In determining whether to approve, reject or send back this proposal, the Authority must consider whether it better facilitates the achievement of the ACOs as compared with the current methodology[48]. The ACOs are set out below:

a. Facilitating effective competition

that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity

b. Cost-reflective charging

that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection)

c. Taking account of the developments of transmission licensees' businesses

[47] As set out in Section 3A of the Electricity Act 1989
[48] The licence sets out that modifications should be made as required for "the purpose of better achieving the relevant objectives".

that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses

d. Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

e. Promoting efficiency in the implementation and administration of the system charging methodology.

Our assessment against the Applicable Code Objectives

4.3. We have considered the issues raised by the modification proposal and the Final Modification Report (FMR) dated 23 September 2021.

4.4. We are minded-to consider that the solution proposed under CMP308 better facilitates ACOs (a), (b), and (e) and has a neutral impact on ACOs (c) and (d). Our reasoning for each ACO is set out below.

ACO (a) Facilitating effective competition

Workgroup and Panel Views

We note most Workgroup participants considered this proposal to better facilitate ACO (a) with the exception of one participant, who considered that, taking this modification in isolation, supplier competition could be hampered. The participant suggests that increases in BSUoS charge payments by suppliers would need to be appropriately reflected in the price cap, and where this cannot happen and suppliers cannot recover costs, supplier competition will be harmed. This participant noted the concerns they raised would be mitigated in the event CMP361 was approved. This party also expressed concerns in the Code Administrator Consultation, considering that ACO (a) was not better facilitated.

The CUSC Panel unanimously agreed this modification would better facilitate effective competition and therefore ACO (a). Panel members generally cited that the proposal would "level the playing field" for different types of generation, and in particular, address the existing difference between the charges faced by domestic Large Generators and continental generation.

Our view

Our analysis agrees with the Workgroup and CUSC Panel that removal of BSUoS charges from generation would address a number of identified distortions in the wholesale market and so is likely to ensure more effective competition. In particular, there is a distortion between Large Generators and other generation within the domestic wholesale market, due to differences in BSUoS charging liability. There is also a distortion between Large Generators and generation that exports into the GB market using interconnectors.

Existing distortions

Taking the examples of two identical generators under the *status quo* arrangements, one a Large Generator and one a Smaller Distributed Generator, we would expect to see a number of effects that distort competition. For example:

- We would expect to see the Smaller Distributed Generators being able to offer cheaper wholesale power, due to the Large Generator needing to factor BSUoS charges into the wholesale price it charges. The inclusion of BSUoS charges in some generators offers and not others may mean marginally more expensive generation edges out less expensive generation, so those running may not always be the most efficient. We think this effect may be particularly important in the case of generation self-dispatch[49].

- A Smaller Distributed Generator may be able to bid lower in Capacity Market (CM) or Contract for Difference (CfD) auctions, which could distort auction outcomes, or could distort balancing and ancillary services markets.

[49] Dispatch of generation in the GB market happens through two routes. The predominant method is through self-dispatch of power stations to meet contractual positions. In this method, generators submit advance notifications to ESO that ensure that their contractual commitments can be fulfilled, telling the ESO when they will run. Closer to the time of delivery, the ESO manages dispatch, ensuring that the system stays in balance and that constraints and other system issues can be managed. We would refer to this as ESO-led central dispatch.

- We would expect to see plant closures affecting less profitable plants with higher costs before those with lower costs, and so in the *status quo* arrangement there may be a distortive incentive to close plants that face BSUoS charges before plants that do not.

The removal of BSUoS charges from those generators that currently face it, as would be the case if CMP308 was approved, would be expected to reduce or remove these effects. On these effects, we welcome feedback on the extent to which differences in BSUoS charging are likely to impact:

- Plant dispatch, including ESO-led central dispatch as well as generation self-dispatch;

- Auction outcomes for support mechanisms; and

- Plant investment, refurbishment and closure decisions.

Impact on competition between CfD generators

As discussed in more detail in the next chapter, we are aware of provisions in existing CfD contracts that could allow continued compensation payments for BSUoS charges to some generators following implementation of CMP308. We recognise that this presents a risk to the consumer benefits associated with the proposed modification and could create a new distortion between different types of generator i.e. if existing CfD generators were to continue to receive compensation, while others did not, that would amount to a new distortion.

We would note the potential impacts of the compensation mechanisms are likely to be front loaded, while the benefits of improved competition are likely to be spread over a number of years. We would expect to see a large number of auctions and auction-linked investment decisions taking place over the coming decades. We think that the removal of BSUoS from generators means auctions will focus more directly on the costs forecasted by participants, rather than differences in the charging regimes that different projects may face. We consider that this is likely to unlock significant efficiencies and that the potential consumer benefits of non-distortive investment in the coming years are sizable, given the role of low-carbon support mechanisms in GB's Net Zero ambitions. Taking this all into account, we still consider the overall impact of the proposal to be positive against this objective. This is because the ongoing reduction in distortions is likely to produce a system that is better set up to achieve Net Zero and better consumer outcomes in the long term. We would expect network users to continue to respond to the changes in charges in the longer term, and the effects of the reduced distortions would be persistent. On the other hand, any impact from the compensation mechanism, while more immediate, would be a one-off impact on generator competition, and would be less likely to have enduring effects on user behaviour, such as dispatch and investment. We think this new distortion is therefore smaller in magnitude than the distortion that is reduced. We welcome feedback on this point.

Impact on competition between different generator types

We note that in increasing the share of BSUoS charges picked up by demand, CMP308 will increase the demand side benefit available to sites with "Behind The Meter Generation" ("BTMG") or onsite generation from offsetting demand BSUoS charges. The share of generation BSUoS charges avoided by BTMG when compared to Large Generators will reduce, and so the cost advantage that BTMG face versus Large Generators (rather than all generation) is not expected to change in the round.

BTMG do not currently face BSUoS charges on their generation, whether this is used on site or exported. In this sense, they are treated similarly to Small Distributed Generators and interconnectors, as neither face generation BSUoS charges. Unlike Small Distributed Generators and interconnectors, BTMG can allow a demand site to reduce its *demand* BSUoS charges below what it would pay if it took power from the networks, as BSUoS charges for demand are not levied on consumed power where that power was generated behind the meter.

CMP308 is expected to increase the size of the BSUoS charge that demand users face, as demand will go from paying c.53% of the costs of balancing the system to paying 100% of the costs. As the demand charge for BSUoS increases, so does the potential value for BTMG in avoiding BSUoS charges.

CMP308 will lead to an increased advantage for BTMG over Small Distributed Generators and interconnectors, as the advantage BTMG have in offsetting demand BSUoS charges will increase, but there is not a corresponding generation BSUoS charging advantage over other non-liable generators that will decrease.

We consider this new BTMG distortion to be smaller than the distortion that would be addressed by the implementation of CMP308. While we consider the increase in BTMG's ability to offset demand BSUoS charges to be material and potentially distortive, we consider it to be smaller than the distortion that exists between Large Generators and all other generators at this point, due to the smaller nature of the BTMG sector[50]. We will continue to monitor this distortion and consider whether further action is needed in this area to prevent consumer harm.

Table 2 - CMP308 impact on different user types

GB BSUoS charge liability	Baseline		CMP308		CMP308 impact	Notes
	Demand	Generation	Demand	Generation		
Final Demand (exc. storage)	✓	✗	✓	✗	Pay more	Demand charge c.2x higher under CMP308. This would see demand share of balancing costs increase from c.53% to 100%.
BTMG	***Offsets***	✗	***Offsets***	✗	Offsets more	Offsets demand BSUoS, do not pay on generation
Smaller (sub-100MW) distribution-connected storage	✗	✗	✗	✗	No change	Storage liable for imports not related to storage operations under both baseline and CMP308. Exempt from demand BSUoS via CMP281.
Smaller (sub-100MW) distribution-connected generation	✓ **on any demand**	✗	✗	✗	No material change	Currently pay BSUoS on any demand, do not pay on generation
Transmission-connected and Large (>100MW) distribution-connected storage	✗	✓	✗	✗	Pay less	Storage liable for imports not related to storage operations under both baseline and CMP308
Transmission-connected and Large (>100MW) distribution-connected generation	✓ **on any demand**	✓	✗	✗	Pay less	Currently pay BSUoS on any demand and generation

[50] The amount of BTMG capacity is less than the capacity of network-connected generation. Importantly for BSUoS charging, the volumes that are supplied by BTMG are lower. Statistics from the Digest of UK Energy Statistics (DUKES) electricity suggest there is c.64GW of Transmission connected generation, c.34GW of distribution connected generation and c.11GW of autogeneration, which is how BTMG is described in that document. In terms of volumes of energy consumed, c.11TWh came from autogeneration, compared to 280TWh from the public distribution system. Therefore under 4% of electricity is currently provided by BTMG and will so will not incur BSUoS charges. Over 96% of consumed power will be from network-connected generation and so will be liable for BSUoS charges. As we state above, we still consider this difference to material, and will continue to monitor this situation, but it is smaller than the existing distortion where Large generation pay BSUoS and all other generation do not. https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

Interconnectors	✗	✓	✗	✗	No change	Exempt from demand and generation BSUoS as per CMP202

Supplier competition

Generation exports from generation situated behind the meter pays BSUoS charges at the same zero rate as all other generation types, potentially improving competition in the generation sector. There may be some knock-on impacts in the CM and CfD markets from this onsite generation effect, and we would invite feedback from stakeholders on this.

We recognise that some suppliers consider this change not to be beneficial for supplier competition as, in removing the charge from generation, suppliers will lose the ability to hedge a portion of the BSUoS charges that their end consumer customers will eventually be liable for. In the case of wholesale power purchased entirely from non-liable generation, they would lose the ability to avoid a contribution to the costs that BSUoS charges recover. We consider, as a cost-recovery charge, that it should not be possible to avoid costs through different purchasing strategies, and to the extent that all suppliers will have to face these charges, supplier competition may be improved. We recognise that sufficient notice periods are required to ensure significant levels of double payments do not occur. It is also important suppliers can effectively pass costs through the price cap. We discuss these issues in the implementation section of this document.

Overall

In the round, we are minded-to agree that CMP308 better facilitates ACO (a) because it would take positive steps toward a more level playing field between different sources of generation, and, in doing so, allow more effective competition in the generation market.

ACO (b) Cost-reflective charging

Workgroup and Panel Views

We note that most Workgroup participants considered the modification to be neutral against ACO (b). One participant felt it had a negative impact, as they considered the proposal would increase the size of the non-cost reflective signals paid by demand. They suggested the increase in the size of the demand BSUoS charge, which currently is a volatile, variable charge, could increase the non-cost reflective signals to change behaviour, for example incentivising users to reduce demand in zones with high costs driven by excess generation, where the opposite incentive would be desirable.

This participant noted the concerns they raised would be mitigated in the event CMP361 was approved, as an averaged, more uniform volumetric charge (as proposed by CMP361) would reduce the strength of these signals. Other participants agreed a more effective improvement to cost reflectivity would be achieved if CMP361 was also approved.

Of the Panel, two members felt this modification better facilitated ACO (b). One member noted that modification could remove "noise" from the wholesale market, and so improve "visibility of genuinely cost-reflective signals".

Our view

In our view, removing BSUoS charges from Large Generators is, in the round, somewhat better for cost-reflectivity. Removing BSUoS charges for those generators removes a non-cost reflective charge, and so therefore should leave more cost-reflective signals. All things being equal, non-cost reflective charges obscuring or altering a cost reflective signal would lead to less efficient economic outcomes, as market participants will receive poorer information about the impact of their activities and so will not properly internalise the cost of their behaviour.

A key example of this would be in BSUoS charges affecting generation dispatch. Dispatch should be led by efficient signals, and the inclusion of BSUoS charges in some generators' offers may alter which generators self-dispatch at a given time. This may mean the generation running may not always be the most cost-effective or efficient. We are minded-to consider that CMP308 would be positive for cost reflectivity, as dispatch signals will not be affected by some generators having liability for BSUoS charges, and not others. We invite views on whether ESO led central dispatch is likely to be subject to the same issues.

We recognise that like all charges, the cost of BSUoS charges may drive marginal decisions by demand side network users. These may be inefficient decisions such as changing system use to avoid BSUoS charges in times of high prices. We acknowledged this in our response to the Second Task Force report, where we noted that the "current floating charge can send unhelpful signals". Where end users are incentivised to use less, this may exacerbate the network issues that are giving rise to high prices and so may form a counter-intuitive signal or perverse incentive.

We recognise that BSUoS charges being covered solely by Final Demand would increase this effect, but consider it is less significant than the distortion to generation dispatch as the majority of demand would not usually be expected to be price driven by real time BSUoS pricing. We do not think a move to demand-only BSUoS charges would mean the aggregate impact of these non-cost reflective signals has grown, but rather they have grown for one set of parties and remained the same overall.

We also consider that in moving to demand, BSUoS charges would be moving from a more price-responsive set of users to a less price-responsive set. For many demand users, particularly domestic users and other small users who are not on pass-through contracts, the charges will not be passed through directly. This means there will be no real signal faced by users from which a behavioural change might be driven. Of users that do have pass through contracts, we would expect a range of price responsiveness depending on user types. For generation users, on the other hand, we would expect price responsiveness to be generally very high. It therefore follows that response to this cost recovery charge is likely to be lower if levied on demand only.

We recognise the risk that the more price responsive demand users may also be those users who have or are more likely to invest in BTMG. As stated, we will continue to monitor the BTMG situation.

The related modification CMP361 aims to replace the existing variable BSUoS charges with a flat volumetric charge. If we approved CMP361, this would potentially mitigate some of these effects, though as a separate modification we make no judgement on that proposal within this consultation. Regardless of the form of the charges, we consider that BSUoS charges being payable solely by demand means they are likely to be less distortive, given the relative responsiveness to prices of the typical generation and demand users. On balance, we are minded-to consider that CMP308 better facilitates ACO (b), but we do think it a relatively minor improvement.

ACO (c) Taking account of the developments of transmission licensees' businesses

Workgroup and Panel Views

Of the three Workgroup members that felt this modification better facilitated ACO (c), one provided reasoning, noting "as interconnection capacity increases, the current market distortion between GB and continental generators will increase. CMP308 takes account of this development and will prevent the existing distortion from becoming exacerbated." A number of Code Administrator Consultation responses focused on the theme of growth in interconnection, and suggested that CMP308 might prevent a perceived worsening of existing distortions between interconnected and GB markets that such growth might bring. Of the CUSC Panel members who supported this ACO[51], one directly addressed this point, noting "the effect of the market distortion between GB and continental generators will increase unless 308 is passed".

Our view

We consider that this modification is on the whole neutral in terms of ACO (c). We have considered whether this change reflects necessary changes in the transmission licensees' businesses. The last significant changes to the arrangements covering which generators were liable for BSUoS charges took place in 2012, when BSUoS charges were removed from interconnectors[52]. Our 2019 TCR Decision removed the Embedded Benefits associated with BSUoS charges, but did not address the difference in liability between Large Generators and other generation.

The level of distributed generation is expected to increase from c.28% to c.33% of capacity by 2030 according to the ESO's FES 2020 Consumer Transformation scenario, and interconnector capacity is expected to increase from c.5GW to c.19GW by 2030 under the FES 2021 Consumer Transformation scenario. Our consultants' modelling suggests that the BSUoS charging treatment has significant impacts on the interconnector flows and on the competitive relationship between different generation types.

[51] Three "Vote 1" panel member voting statements supported the view that this objective was better facilitated, though only one listed objective c) as being better facilitated in the "Vote 2" table within the FMR.
[52]Demand BSUoS charges were removed from interconnector BMUs under CMP202, raised by NGET. https://www.ofgem.gov.uk/sites/default/files/docs/2012/08/cmp202-decision-letter_0.pdf

This modification removes BSUoS charges from Large Generators, bringing it in line with interconnectors and Smaller Distributed Generators. This is important, given the increasing contribution of these generation types.

However, while it could be argued that this change is important in light of changes to the market, we would consider this argument effectively collapses into an argument for improved competition. In effect, there exists a distortion to competition and we consider that CMP308 would provide an improvement as explained under ACO (a) above. A non-discriminatory regime where BSUoS charges do not fall only on certain generators is more consistent with a system where increasing amounts of generation is not transmission-connected or large distribution connected domestic generation, but this is addressed by ACO (a).

ACO (d) Compliance with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency for the Cooperation of Energy Regulators

Workgroup and Panel Views

No Workgroup members felt this ACO was better facilitated. Three Code Administrator Consultation responses did support this, with one suggesting benefits to compliance with EU law. One Panel member also felt the change could better facilitate compliance, noting they agreed with the rationale set out in the original proposal. In broad terms, the proposal suggests that ACO (d) is better facilitated as reducing market distortions will help to deliver the full benefits of a competitive internal market, something particularly relevant in the context of interconnector growth.

Our view

We believe that ACO (d) is not relevant for the modification. We are minded to consider that moving BSUoS charges only to demand does not, in our view, affect compliance with the Electricity Regulation or other relevant legally binding decisions. It is our view that the impact is neutral, a view shared by all but one Panel Member.

ACO (e) Promoting efficiency in the implementation and administration of the charging methodology

Workgroup and Panel Views

A number of Workgroup members suggested this ACO was better facilitated by CMP308. In particular, they felt that cost recovery from Final Demand is more efficient than from generation and storage, and so a change to reflect this fact would improve the efficiency of the charging methodology. Two other members suggested the changes would better align BSUoS charging and TNUoS charging terminology. Another member felt CMP308 would simplify the charging and billing arrangements, which would consequently simplify administration. The Code Administrator Consultation saw a number of responses supporting the modification as better facilitating objective (e), but no qualitative statements were provided. Six Panel members felt this ACO was better facilitated, with one suggesting it might better facilitate efficiency in the implementation and administration of the charging methodology.

Our view

We agree that simplified arrangements would have a positive impact on ACO (e) as they facilitate efficiency in the implementation and administration of the use of system charging methodology. We understand that the ESO also aims to implement CMP308 using a new ESO billing system to improve process efficiencies.

4.5. In summary, we are minded-to agree with the CUSC Panel's recommendation that this modification better facilitates the ACOs than the baseline methodology.

Summary of minded-to assessment against the ACOs

Table 2 - Minded-to assessment of CMP308 against the ACOs

Proposed Solution	Does the proposal better facilitate the ACO?				
	ACO (a)	ACO (b)	ACO (c)	ACO (d)	ACO (e)
Original	Yes	Yes	Neutral	Neutral	Yes

Assessment against the Authority's statutory duties

4.6. In making a decision on this modification proposal, we have to act in accordance with our Principal Objective and statutory duties. In this regard, we consider that implementing CMP308 is in the best interests of existing and future consumers because we expect more effective competition is likely to lead to a system that is, in the round, more likely to deliver lower cost generation investment. This is particularly important in the context of the UK's legally binding targets around decarbonisation. If the generation investment needed to ensure GB has secure supplies of low-carbon power is not made on an efficient basis, it may not deliver the optimum solutions for the market, and Net Zero may be delayed, more costly than necessary[53], or both. We consider that our impact assessment, set out in section 5, suggests change is likely to bring about more efficient generation investment and market functioning, which is likely to lead to reduced consumer costs.

4.7. We consider the proposal to be consistent with our Principal Objective and statutory duties. In particular, we have a statutory duty to consider persons who have a disability or are chronically sick, have a low income, are of pensionable age, or reside in rural areas. Our assessment is that there is a low estimated financial impact on all domestic users, and as such we do not consider this policy change to have a significant impact on the users outlined above. This is considered in more detail in our distributional assessment later in this document.

Impact on emissions and Net Zero

4.8. The decarbonisation impacts of this modification are complex, and interact with our statutory duties including (but not limited to)consideration of the reduction of greenhouse gases in the context of discharging our principal objective. Our modelling indicates that more GB electricity would be provided by Combined Cycle Gas Turbines (CCGTs), as improved competition between CCGTs, which tend to be Large Generators, and other types of generation, is likely to mean more are built. This increases the amount of GB CCGT generation. As a result of the increase in generation from CCGTs, the CMP308 reform is expected to increase net UK emissions[54] but reduce carbon emissions in interconnected markets, such as the EU and Norway such that the overall impact of the proposed change is expected reduce emissions (if considered in the round).

4.9. The effects of this modification, when measured across GB and its neighbours, are an expected reduction in carbon emissions. If we consider impacts solely on a GB basis (and not more broadly to include neighbouring countries) the cost of carbon abatement for the GB economy as a whole is likely to increase. Such a cost would not be seen as a financial impact on electricity bill payers, but as a cost to the GB economy associated with abatement. Due to

[53] We discuss the likely impacts of CMP308 on emissions and our Net Zero obligations in detail later in this document. We also consider the economic costs of emissions abatement.
[54] That is to say, if the island of Great Britain is considered in isolation, emissions from the power sector will increase as a result of this modification.

these dynamics, we consider that taken in the round, this is a broadly beneficial modification from a global carbon emissions perspective, while simultaneously being potentially more costly from a GB decarbonisation perspective. We invite feedback on these issues

4.10. Overall, we think this change is likely to make the investment needed to achieve Net Zero targets more efficient, in that it removes a potentially volatile charge from generation investment that is only paid by certain parties, and in doing so improves the functioning of the market. While the modelling that has informed this minded-to decision suggests that many benefits will come from increased investment in gas generation, we recognise it equally will make for a more level playing field for renewable investments and for storage. The modelling is a useful indicator of how the system may develop, and provides insight on the direction of changes and the moving parts affected by a decision. Other possible futures exist, and it is reasonable to assume that a less distortive investment environment with more cost reflective signals will ensure a more efficient transition than would otherwise be the case, whatever the specific investments made. Without differences in BSUoS charges, sizing and connections decisions for projects will be driven by what is most efficient for the site and project in question, and will not be shaped by the different regimes for Large and other generators.

Impact on markets and investment

4.11. We expect this change to remove distortions from wholesale markets and to a lesser extent to CM and CfD markets, which is likely to bring consumer benefits. Significant levels of investment are expected in the coming years, and the removal of distortions should ensure this takes place in the most efficient way possible. We recognise that in order to meet the UK's legally binding decarbonisation targets, substantial renewable and other low carbon investment is required to take place. Given the multiple paths possible in the transition to a Net Zero economy, we think that removing distortions between generators of different size and connection voltage is likely to increase the ability of the market to choose the most efficient solutions, rather than being pushed towards certain investments by the charging arrangements.

4.12. A significant change predicted by our modelling is that the conventional generation that is built is of a more efficient type, and also that small distribution connected batteries are displaced where they were previously built. We consider that this is indicative of a general move towards a less distorted market, rather than CMP308 favouring conventional generation, and consider that the modification is equally likely to improve competition between Large generators of a renewable nature and other generators of a non-renewable nature. Additionally, CMP308 removes BSUoS charges from exports from Large electricity storage[55], which might affect dispatch and investment decisions.

4.13. We think that the cost difference evident between different types of generators due to existing BSUoS charging arrangements is unlikely to lead to the most efficient investment. In a world where renewable investment may take place without the need for subsidies, we would expect benefits from a more level playing field in ensuring that investment is located and connected in the most efficient way. We invite views on these dynamics from stakeholders.

4.14. Broadly, we consider this modification to be neutral in terms of security of supply, and consider it to be positive for decarbonisation, as it is expected to lead to a net global reduction in emissions. Given there are complex issues surrounding this modifications impact on carbon emissions and the societal costs of the GB Net Zero transition, we invite stakeholder feedback.

Relationship to the TCR

4.15. As noted above, the key feature of this proposal is the move from charging BSUoS, which is a non cost-reflective charge, from generation and demand solely to Final Demand. There are similarities with conclusions reached in our TCR Decision, where we decided that residual charges, as non cost-reflective charges, should be borne solely by Final Demand. We would stress that this minded-to decision is not part of the TCR SCR and is not covered by the principles of that review, though we do consider our minded-to position to approve CMP308 would align to our wider charging strategy.

Minded-to decision

4.16. We have considered the issues raised by the modification proposal and the Final Modification Report (FMR). We have considered and taken into account the responses to the industry consultations on the modification proposal which are attached to the FMR. We are minded-to conclude that:

- Implementation of CMP308 will better facilitate the achievement of the ACOs than the baseline methodology; and

[55] Following CMP281, which was approved in May 2020, storage do not face demand BSUoS costs. Exports from storage are treated in the same way as generation.

- Directing that the modification be made will be consistent with our Principal Objective and statutory duties.[56]

4.17. We are minded-to consider that CMP308 will better facilitate the ACOs. We consider that we should consult on our minded-to position and impact assessment before reaching our final CMP308 determination. Our minded-to decision is therefore to direct that the modification be made. We will discuss implementation timelines later in this document.

[56] The Authority's statutory duties are wider than matters which the CUSC Panel must take into consideration and are detailed mainly in the Electricity Act 1989 as amended.

5. Assessment of Costs and Benefits

Section summary

This section considers how the costs and benefits of moving BSUoS charges to Final Demand can be quantified. It explains the method, main assumptions and results from the wider system modelling and also the challenges. It also identifies important hard-to monetise costs and benefits that are part of our assessment of the proposed modification.

Questions

11. Do you have views on the modelled assessment of consumer and energy system benefits? Please provide quantitative analysis and any further information.
12. Is our assessment of non-monetised costs and benefits reasonable? Are there any other factors we should consider?
13. Do you consider the consumer and system benefits identified in our consultants' modelling to represent a reasonable view of the potential effects of this modification?
14. Do you consider that Ofgem has duly considered all relevant consumer and system benefits? Are there any areas which could benefit from further analysis?
15. Our modelling assumes that CfD adjustment payments designed to compensate contract holders for the BSUoS charges they face will no longer be paid in the event generation is not liable for BSUoS charges. Do you agree with this assumption, and do you have views on our assessment of the risks associated with existing CfD contracts?

System and Consumer welfare impacts

5.1. Our assessment of the impact of moving BSUoS charges to Final Demand aims to apply principles of cost-benefit analysis consistent with the HMT Green Book,[57] BEIS/HMT guidance[58] and our own guidance[59].

[57] The Green Book (publishing.service.gov.uk)

[58] Valuation of energy use and greenhouse gas emissions (publishing.service.gov.uk)

[59] Impact Assessment Guidance | Ofgem

5.2. To assess the quantified impacts of implementing this proposal, we commissioned Frontier Economics and Lane Clark and Peacock (LCP) to carry out analysis[60] of:

1. The costs to users (thereby quantifying consumer welfare).

2. 'Wider' system costs which refers to the impact on the wider energy system including unpriced carbon (measuring the societal impact of the reform).

3. Distributional impacts of the proposed reform (reported in section 6).

5.3. Treasury guidance[61] recommends when a policy has a marginal impact on emissions, and some of these reductions are outside GB, to consider external emission as well as national emissions. Our published analysis of wider benefits (which include unpriced values for carbon) followed this principle and provided information on wider system costs on a GB only basis as well as effects outside GB.

5.4. We would direct stakeholders intending to respond to this consultation to our consultants' report for full details and context and the supplementary LCP slides 'BSUoS wider system modelling with updated Carbon Appraisal Carbon Appraisal Values for Ofgem'[62].

5.5. The analytical period for the costs to users and the 'wider' system costs is between 2023 and 2040. Costs and benefits over this period are measured in real 2020 prices. Discounting is carried out at the Treasury rate of 3.5% to give Net Present Benefits, Costs or Values in 2022.

Assessment Methodology

5.6. Our consultants have used LCP's proprietary EnVision model. This is a well-established fully integrated model of the GB power market. As described in section 2.1 of the consultants' report, it can measure the likely short-term dispatch and operational responses that could result from the proposed changes to BSUoS charges. It can also simulate long term plant investment and retirement decisions that might result from the change.

[60] LCP/Frontier report - Wider System and Distributional Impacts of Recovering Balancing Services Costs From Demand
[61] Valuation of energy use and greenhouse gas emissions (publishing.service.gov.uk)
[62] LCP modelling - BSUoS wider system modelling with updated Carbon Appraisal Values for Ofgem

5.7. The model can provide insights into how the proposed change feeds into generation economics, the generation capacity mix, Capacity Market (CM) auctions, low carbon subsidy costs, wholesale prices and carbon emissions.

5.8. In the modelling, a comparison is made between a *status quo* counterfactual where BSUoS charges are recovered from both Large Generators and all demand based on a per unit energy charge (£/MWh) set *ex post*, and a factual where BSUoS charges is recovered from only suppliers on a variable £/MWh basis[63]. This comparison assumes all generation sources placed 'in front of the meter[64]' are on a level playing field. BTMG can be used to reduce a suppliers' import volume by reducing the number of units taken from the networks on which BSUoS charges would be levied. The factual assumes BTMG would get a greater advantage from reducing BSUoS charge exposure for load due to the higher BSUoS demand charge, but also that it would not avoid the generation BSUoS charge that BTMG can avoid in the counterfactual scenario.

5.9. It is important to both use a credible 'Business as Usual' baseline and to consider uncertainty in analysis, otherwise results may be misleading or only relevant to a particular development of the energy system. Our consultants' report presents results for two credible pathways of system development described in National Grid's FES 2020 documents.[65] These are Consumer Transformation (CT) and Steady Progression (SP). These scenarios provided assumptions on market and system developments such as commodity prices, demand, low carbon build and interconnector build.

5.10. In this document we treat CT as the reference scenario, as it meets the UK's Net Zero obligations set out in the amended Climate Change Act 2008. Key elements of this scenario are that consumers are willing to make large changes in energy related behaviours, there is a high degree of heating electrification, high energy efficiency is achieved and there is considerable demand side flexibility. In contrast, SP has progress on decarbonisation but with little decarbonisation of heat and little change in consumer behaviours. The underlying mechanisms that give rise to benefits are similar for both scenarios, and for this reason, we concentrate on

[63] In simple terms, the counterfactual here represents the existing arrangements as they might develop over time, while the factual scenario represents the development over time of the system if we approved CMP308

[64] Generation "in front of the meter" is connected to one of the public electricity networks, such as the transmission or distribution networks and primarily serves to supply electricity to users on other sites using the networks. Generation sited "behind the meter" is that which primarily supplies demand situated on the same site, rather than elsewhere. Some BTMG will also export on to the network, and for that power consumed off-site will be typically treated as any other comparable generator.

[65] FES 2020 documents | National Grid ESO

the detail of CT. However, similar information is available in the consultants' report for SP, with significant differences highlighted.

5.11. The annual average BSUoS charge projections under each scenario over time are illustrated below.

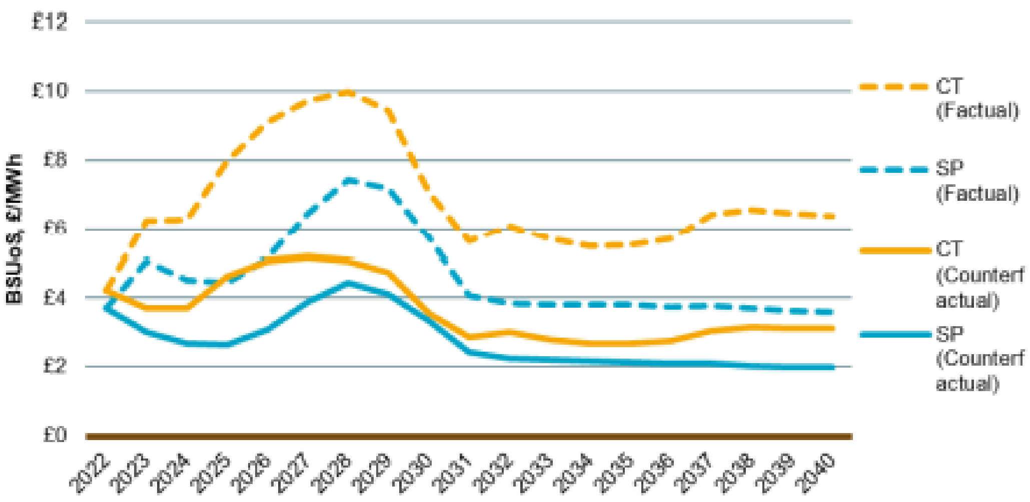

Figure 1 - Annual BSUoS Charge projections. Source: LCP/Frontier

Assessment Findings

5.12. In simple terms, as BSUoS charges are currently levied in approximately equal measure on generation and demand, the charges might be expected to approximately double if placed on demand alone as a result of the proposed reform[66]. However, the generation charging base is slightly smaller than the demand base, due to the specific arrangements described earlier in this document where interconnectors and Small Distributed Generators supply demand but do not pay BSUoS charges. These characteristics are reflected in the starting position of our model. In future years, the generation charging base grows compared to the demand charging base, with more domestic generation exporting to interconnected markets.

[66] Currently, BSUoS charges are levied on each MWh of generation from liable generators, and each MWh of supplier demand. Moving BSUoS only to demand means the overall number of units over which the BSUoS in total is charged approximately halves. To put it another way, the denominator of the current BSUoS calculation is all liable generation MWh and all liable demand MWh. If CMP308 is approved, the denominator will be only the liable demand MWh and the unit rate will approximately double.

5.13. The modelling suggests that the move to demand only paying BSUoS charges sees similar peaks and lows in average BSUoS charges across the year to the status quo arrangements modelled in the counterfactual option, but with demand charges typically 1.5 to 2 times higher, reflecting the smaller charging base under CMP308. This can be seen in the charts below, which we reproduce from our consultants' report. The charts[67] show the BSUoS charge projections for an average summer day in the year 2025, highlighting that during the summer, when demand is low, BSUoS charges tend to be high at night. This sends a perverse signal to users, as more demand would reduce balancing costs.

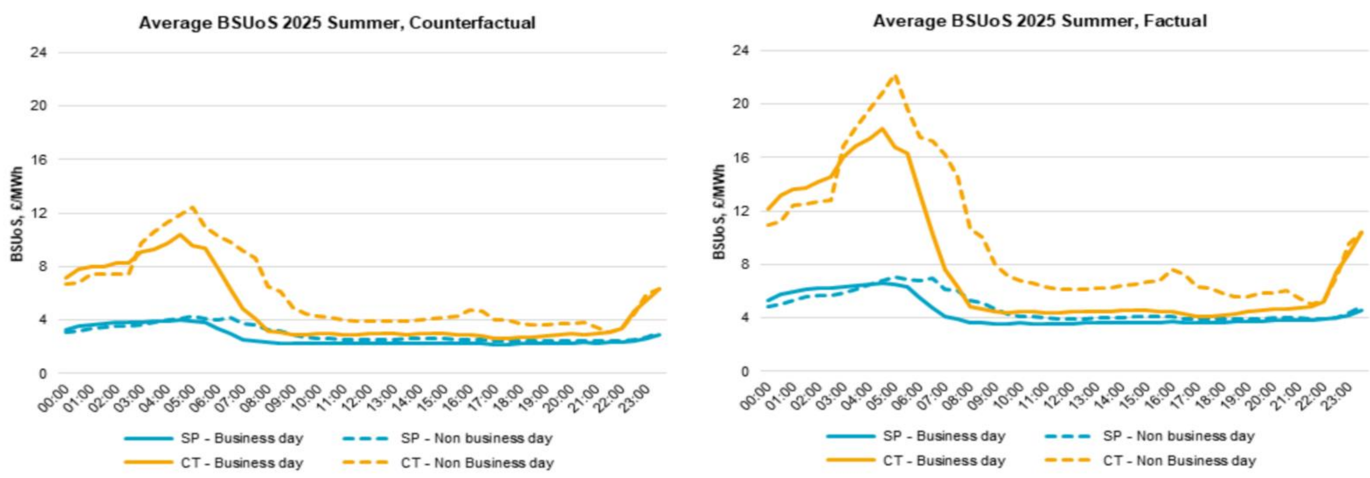

Figure 2 - BSUoS charge projections, £/MWh, Status Quo (Counterfactual) at left, CMP308 demand only BSUoS (Factual) right. Source: LCP/Frontier

Wholesale prices

5.14. GB is unusual in Europe in having material levels of charges for balancing services levied on generation, and GB BSUoS charges are significantly higher than balancing charges faced by generators in the countries GB is or will be interconnected to[68]. Under both CT and SP scenarios, the removal of BSUoS charges from generation leads to more generation from CCGT plants and lower output from storage and peaking plant[69]. The removal of BSUoS charges leads to

[67] The report includes four graphs showing BSUoS charges for an average winter day as well as the summer charts shown above.

[68] As set out previously, balancing services charges are not charged to generators in France, Ireland or the Netherlands, and levels faced by generation are much lower than generators in GB in Belgium, Norway and Denmark. More information can be found in the second BSUoS Task Force report http://www.chargingfutures.com/media/1477/second-balancing-services-charges-task-force-final-report.pdf

[69] Peaking plant are typically natural gas-powered reciprocating engines or gas or oil fired open cycle gas turbines, They have lower efficiency than CCGTs, but ramp up faster and typically have lower capital costs.

wholesale price decreases in both scenarios, as generators no longer pass through these costs in their wholesale market prices.

5.15. We would expect that wholesale costs fall when BSUoS charges are removed from generators, but only in cases where the marginal – and so price-setting - generator pays BSUoS charges currently. Where a period's marginal generator in the status quo does not pay BSUoS charges, for example if they are a Smaller Distributed Generators, we would not expect the wholesale price to fall if BSUoS charges were removed from Large Generators[70]. In later years, under the CT scenario, there are fewer periods in which the marginal generator is one that is currently liable for BSUoS charges. This means fewer periods where the removal of BSUoS charges feeds through into lower wholesale prices. Under the SP scenario, there are more periods in which CCGT is at the margin in the counterfactual and the reduction in wholesale prices is stronger.

5.16. Figure 3 shows the projected wholesale price difference between the *status quo* arrangements (Counterfactual) and the changes proposed in CMP308 which move BSUoS charges to demand only (Factual). These are shown for the CT scenario. The chart shows the way which wholesale reductions become less significant as the system develops to one with more generation supported by CfDs or that is not domestic Large Generators. More information on these dynamics can be found in our consultants' report.

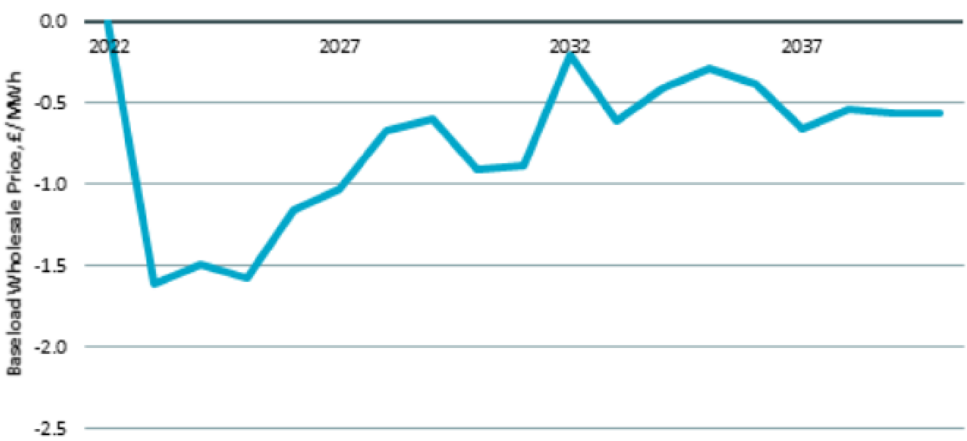

Figure 3 - Wholesale Price (Factual – Counterfactual) Consumer Transformation. Source: LCP/Frontier

[70] Put another way, when generation connected to the GB market via interconnectors or distribution networks, or supported by CfDs set the system marginal price, we would not expect to see a reduction. This is the case in the majority of periods in the counterfactual for the CT scenario in later years.

Consumer Benefits

5.17. Figure 4 for the CT scenario illustrates how, through time, a move to demand only BSUoS charging leads to net consumer benefits of £320m[71]. Initially, the total impact from lower wholesale costs, lower low carbon support payments such as CfDs (where new generators are no longer building BSUoS charges into their auction bids) and lower CM payments is insufficient to outweigh additional BSUoS charges. Low carbon support payment reductions and the lowering of CM payments in future years drive the consumer savings (yellow and pink bars). As these increase over time, overall consumer costs reduce. This is due to the reform levelling the playing field for new generation capacity, leading to more efficient and cost-effective generation being built, as the less distortive markets mean lowest cost generators are built and dispatched first, as markets and auction are not distorted by participants facing different levels of BSUoS charges. Under the SP scenario, the wholesale cost reductions are more significant, in some years falling by more than £2/MWh. More information is available in section 2.4 of our consultants' report.

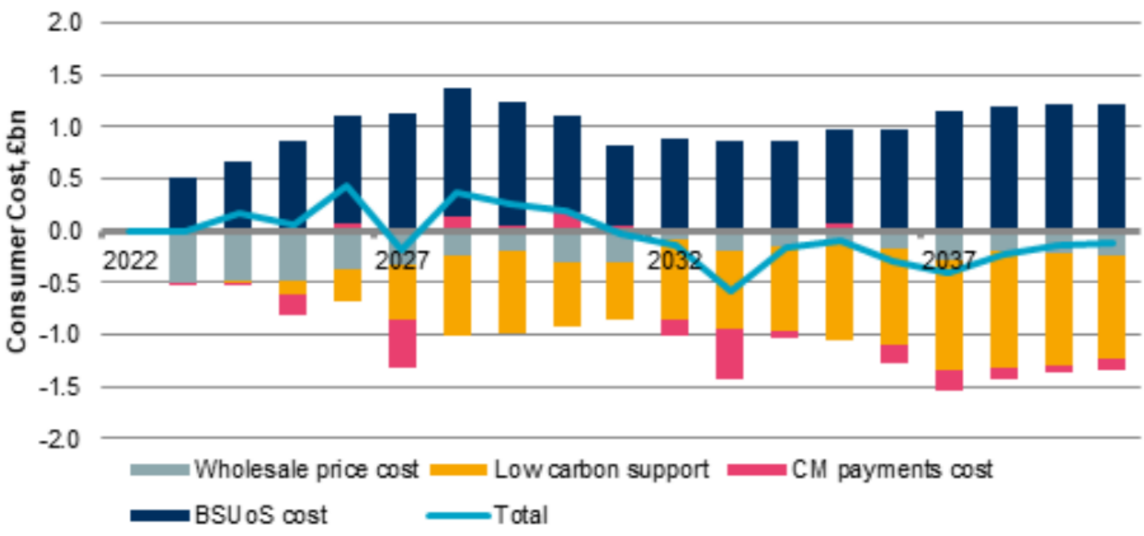

Figure 4 - Consumer Cost (Factual – Counterfactual). Source: LCP/Frontier

[71] 2022-2040 NPV, 3.5% discount rate

Capacity

5.18. The modelling suggests that under both CT and SP scenarios, CMP308 is likely to lead to an increase in the number of Large Generators, in this case transmission connected CCGTs. This comes at the expense of smaller distribution-connected gas peaking and battery storage, who do not pay BSUoS charges under the *status quo* arrangements and therefore do not benefit from the levelling of the playing field (see sections 2.4.1 and 2.4.2 of our consultants' report).

Figure 5 - Capacity (Factual-Counterfactual) Consumer Transformation. Source: LCP/Frontier

Generation

5.19. Under CT, new and existing CCGTs provide more volume in early years, displacing interconnected generation and distributed peaking plants. However, as this is a Net Zero consistent scenario, wholesale price decreases driven by the removal of BSUoS charges from generation cause further exports across the interconnectors with offshore and onshore wind providing the marginal source of generation. Hence, in early years interconnector imports are displaced by increases in domestic CCGT generation and in later years' exports are increased by wind becoming more competitive with interconnected markets' generation once the playing field is levelled.

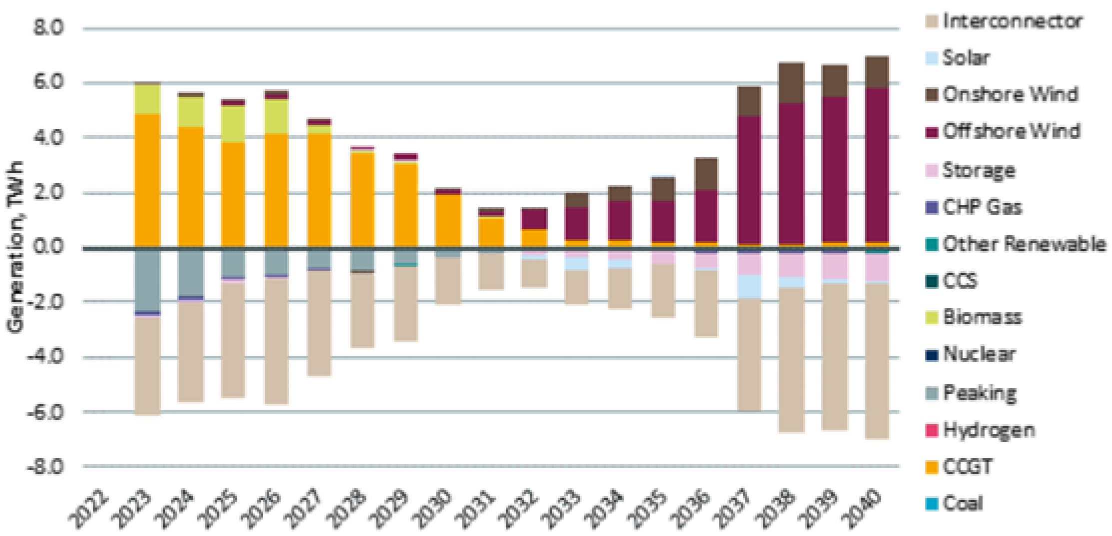

Figure 6 - Generation (Factual –Counterfactual) Consumer Transformation. Source: LCP/Frontier

5.20. Table 4 summarises the benefits to consumers from these changes under both the CT and SP scenario. The system modelling supports our assessments indicating potential benefits from the changes proposed in CMP308, and suggests there are potentially greater benefits if decarbonisation proceeds more slowly than anticipated.

Table 3 - Consumer benefits from applying BSUoS charges to Final Demand only

	Consumer Benefits, NPV terms
Steady Progression	£370m
Consumer Transformation	£320m

Emissions

5.21. The impact on emissions of changing from the *status quo* to a situation where all BSUoS charges are levied on Final Demand is derived from our consultants' modelling. However, the assessment and valuation of these impacts in the context of the UKETS and EUETS which have caps on emissions is complex and we would welcome views in this regard.

Modelled Emission Quantities

5.22. The modelled impact of CMP308 on carbon emissions is shown below for the CT scenario in Figure 7. We can see that when estimated emissions for interconnected generation are accounted for, CMP308 leads to lower overall emissions, with the reduced emissions from peaking plant and interconnected generation slightly outweighing increased emissions from CCGTs[72]. The SP scenario sees more CCGT emissions, alongside lower emissions associated with interconnector flows and less peaking plant emissions compared to the CT scenario. More information on the results for the SP scenario are present in our consultants' report.

5.23. For context, if the change in average annual emissions modelled in CT over the first 5 years of analysis are compared to the current UK ETS cap (156 mtCO2e) they equate to 0.65% of UK traded emissions.

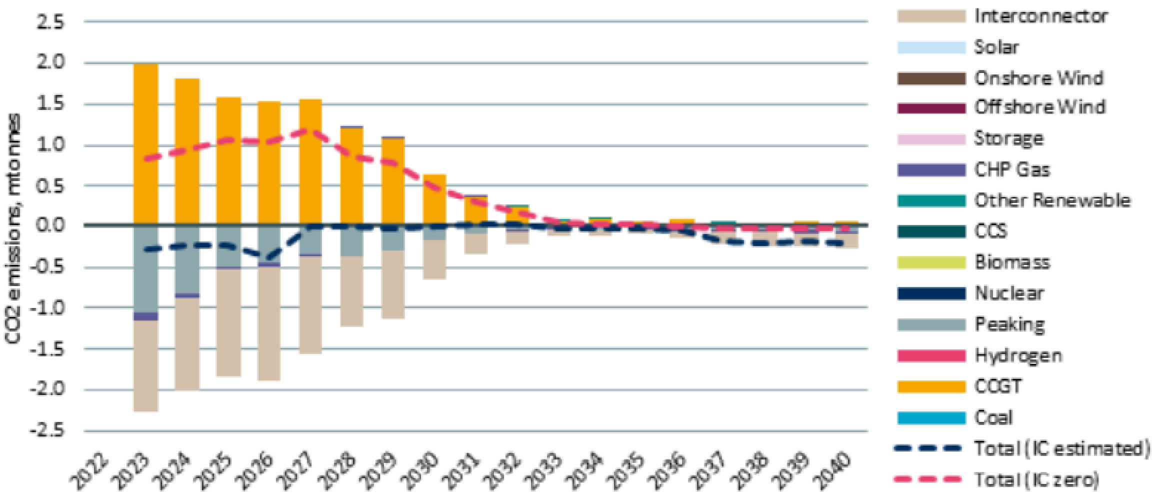

Figure 7 - CO_2 Emissions (Factual-Counterfactual). Source: LCP/Frontier

5.24. The analysis of the removal of BSUoS charges from generation indicates an increase in sectoral carbon emissions when calculated on a GB territorial basis (not including the change

[72] The emissions associated interconnector flows are estimated. It is assumed that the generators flowing over the interconnectors have the same carbon intensity as the nearest domestic generator within the GB merit order. This would broadly lead to interconnector emissions that are higher during periods of high demand on the GB system when emissions are higher, and lower when demand is lower.

in emissions in interconnected markets). In the figure above this is shown by the dashed pink line.

- There is an estimated increase of 8 million tonnes CO_2 equivalents during the modelled period. For context, this is 0.15% of the CO_2 equivalents emitted by the economy if the UK follows the Climate Change Committee (CCC) planned emission pathway for Net Zero.[73]

- The SP scenario modelling estimates an increase in emissions of 12 million tonnes CO_2 equivalents (0.23%) of CCC pathway carbon emissions in the same period.

If we include an estimate of the change in emissions outside GB as well as GB emissions, overall carbon emissions are reduced by the proposed reforms, by 2 million tonnes under the CT scenario and by 4 million tonnes under the SP scenario.

Valuation of emissions

5.25. The overall consumer and system benefits depend on the approach taken to emissions associated with power traded across interconnectors. Table 5 shows the estimated wider system costs under the CT scenario, which include a societal valuation of carbon emissions based on the cost of carbon abatement. Note there is a great deal of uncertainty about precise abatement costs, and this is reflected in the low and high series shown within brackets in Table 5.

5.26. Emissions were costed using 2018 BEIS traded-carbon appraisal values. BEIS recently published new carbon appraisal values, which are different[74] to those used in the cost benefit analysis that we published in July[75]. When the report was prepared in July, the relevant carbon values were the 2018 figures. Since then, BEIS has updated carbon values and so we have updated the analysis to reflect those updated values.[76] The new and old values are shown in slide 4 of the LCP supplementary slides[77] and their impact on NPVs in slide 16.

[73] Sixth Carbon Budget - Climate Change Committee (theccc.org.uk)
[74] The new carbon values are seven times greater than the previous traded values.
[75] UK ETS traded and non-traded emissions are now valued at the same value.
[76] The substantial change in estimated system benefits following BEIS's publication illustrates the sensitivity of monetised benefits to assumptions.
[77] https://www.ofgem.gov.uk/sites/default/files/2021-12/2021-11-12%20Ofgem%20BSUoS%20results%20-%20updated%20carbon%20appraisal%20values%20incl%20market%20price%20%28003%29.pdf

Table 4 - Wider benefits from applying BSUoS charges to Final Demand only

With 2020 Carbon central series values (low and high series estimates in brackets)	Wider benefits for society, including emissions in other markets, NPV (£m)	Wider benefits for society, not including estimate of emissions in other markets, NPV (£m)
Steady Progression	£1,860 (£1,400 to £2,310)	-£1,240 (£10 to -£2,500)
Consumer Transformation	£810 (£600 to £1,020)	-£1,070 (-£190 to -£1,950)

5.27. We asked our consultants to estimate the baseline costs that relate directly to the electricity system, by removing the carbon abatement effects. These remaining costs represent the actual resource cost of running the system, such as materials, supplies, equipment, technologies and facilities, purchase of priced carbon allowances. This approach suggests the electricity system would save £400m in costs if CMP308 were implemented[78].

5.28. With the scope of the assessment encompassing emissions changes in interconnected countries, both the carbon emissions and the cost of meeting emission targets will decrease across UK and interconnected countries, when taken as a whole. For example, the proposed marginal costs of abating carbon in France are similar to those in GB[79]. If emissions have the same cost of abatement in interconnected countries the system impact would be valued at a saving of £810m.

5.29. If the assessment is limited to GB territorial emissions, and emissions changes as a result of this policy where they occur outside GB are excluded, significant additional costs are attributable to CMP308. This is due to the additional 'unpriced carbon' costs attributed to the electricity system. These costs stem from the requirement for the economy as a whole to achieve its carbon targets. Using BEIS's updated figures, the final result is that there is an additional cost of £1,070m, with the unpriced carbon detriment valued at £1,470m. This illustrates that in this instance, the valuation of the abatement of energy production emissions

[78] This analysis estimates the system cost saving as £400m in the CT scenario and £960m in SP.
[79] Carbon values literature review (publishing.service.gov.uk)

becomes the dominant factor in GB 'wider system costs' rather than the direct costs of the energy system.[80]

Contracts for Difference

5.30. The modelling indicates that low carbon support payments, both in the form of Renewable Obligation Certificates and Contracts for Difference (CfDs), will reduce if BSUoS charges are removed from Large Generators.[81] This represents a sizeable portion of the modelled change in composition of consumer costs.

5.31. One of the assumptions in our consultants' modelling is that CfD contracts are adjusted for generators with early and bespoke contracts. Under existing CfD contracts, generators that currently pay BSUoS charges receive an annual strike price adjustment to protect them from fluctuations in average BSUoS charges paid by GB generators using a Strike Price indexation formula. This adjustment is designed to make the CfD contract broadly neutral to variations in BSUoS charges in the long-term.

5.32. We are aware of provisions in the CfD contract that could allow continued compensation payments for BSUoS charges ("BSUoS protection") to existing CfD projects for a period after Large Generators cease having to pay BSUoS. This BSUoS protection issue was highlighted by BEIS in their recent consultation ahead of CfD Allocation Round 4[82] (AR4). In that consultation, BEIS signalled its intention to amend the standard terms of the CfD contracts to remove BSUoS protection from the existing adjustment formula for any CfD contracts awarded in that round, in the event CMP308 is approved.[83] The effect of this change would be that successful AR4 applicants would not receive any compensation for BSUoS charges from the date CMP308 takes effect. We are minded to agree with the view of BEIS that it would not be appropriate for CfD generators to continue to receive BSUoS protection for these charges through the CfD if they no longer have to pay them, and consider that this applies to not only future, but also existing

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[80] Initially, this had a limited effect and our consultants' report showed a saving of £290m using previous BEIS emissions factors, with the unpriced carbon detriment valued at £110m. For the SP scenario, using the new BEIS values, similar unpriced carbon detriment adjustments change a system cost saving of £960m to £1,240m additional cost.
[81] Biomass generation is expected to benefit from the removal of BSUoS, meaning it generates more. Existing CfD-supported wind plant may also benefit. This is because although strike prices will be adjusted down to reflect BSUoS costs being removed, the current CfD adjustment to strike prices is based on volume-weighted BSUoS costs and wind-weighted BSUoS charges are higher.
[82] Contracts for Difference for Low Carbon Electricity Generation: Consultation on further drafting amendments to the CfD contract for Allocation Round 4 (publishing.service.gov.uk) . More general information on the round can be found at https://www.cfdallocationround.uk/
[83] Contracts for Difference for Low Carbon Electricity Generation: Consultation on further drafting amendments to the CfD contract for Allocation Round 4 (publishing.service.gov.uk)

contract holders. Significant levels of continued BSUoS protection following the implementation of CMP308 could result in windfall gains for the generators concerned.

5.33. It is our understanding that, without changes to existing CfD contracts, the BSUoS protection would continue to compensate existing CfD holders for a period after the date our decision takes effect. It will require contract amendments to align the removal of BSUoS protection with the date that our decision takes effect. This is because BSUoS protection is based on historic data, with the changes to the average BSUoS charge of the period running from February to January of one year applied to the period running from April to March of the following year. As a result, any changes to average BSUoS charges take about 14 months to be reflected in Strike Prices. The adjustments are based on average BSUoS charges paid by all generation, which may differ from the costs that fall on individual generators, who will face BSUoS charging costs related to their particular dispatch patterns. As a result of these arrangements, contract amendments will be required to align the removal of BSUoS protection with the date that our decision takes effect.

5.34. If, for any reason, existing CfD contracts were not amended to remove the entitlement to BSUoS protection with effect from the implementation of CMP308, the continued payment of the BSUoS protection would significantly reduce the consumer benefits of this proposal. This is because there would be a period following implementation of CMP308 where CfD generators would continue to be compensated for costs that they would no longer be incurring[84].

5.35. We have estimated the potential maximum impact of this effect outside of the modelling and understand that the worst-case impacts of the continued payment would be likely to result in additional consumer payments in the first 14 months (which would reduce the consumer benefits), and corresponding aggregate windfall gain by the relevant CfD generators, in excess of £200 million. We understand that the Low Carbon Contracts Company (the counterparty to CfD contracts) will engage with generators to effect the requisite contract changes to allow for the full benefits of the proposal to be realised.

Impact on commercial arrangements

5.36. The proposed removal of BSUoS charges from generation was a key recommendation of the BSUoS Task Force in September 2020. We published our agreement in principle in

[84] Because of this lag in BSUoS adjustment, generators would continue to be paid BSUoS for 24 months after they no longer pay it, partly at the full rate, and partly at a reduced rate.

December 2020, confirming that April 2023 would be an appropriate target for implementation of the reforms, but making clear an impact assessment and further assessment of the detail was needed. Our previous work on the TCR set out our views that residual and cost recovery charges should not be paid by generation. We are therefore of the opinion that a typical market participant will have understood that change could occur to the BSUoS charging arrangements for a number of years prior to a 2023 implementation and will have had the opportunity to consider their approach to these uncertainties, including the effect on their commercial arrangements. We welcome feedback from market participants on the impacts of these proposed changes on their commercial arrangements[85] assuming an implementation date of April 2023.

Security of supply in the monetised benefits

5.37. It is assumed in our quantified work that the current GB security standard (Loss Of Load Expectation of three hours per year) is maintained throughout the modelling period (though with some prudence factored into the capacity requirement calculation) and that the current Capacity Market regime remains in place.

Limitations, key assumptions and risks

5.38. Careful modelling work helps us to make sets of assumptions explicit and provides a route for stakeholders to challenge these. There are limits to the precision and accuracy of any modelling, but it facilitates engagement with affected parties. Assessing the impacts of significant change to a complex system is inherently uncertain and there are limitations to the analytical approaches set out in this document, and in any other alternative approaches. Full discussion on the limitations to the assessment of net benefits and distributional analysis are set out in the published report from our consultants published in July 2021.

5.39. As with all modelling, our consultants' work uses a number of simplifications and assumptions, covering areas such as future system demand, generation capacity, market prices and renewables build out. It is our view that a key use of this modelling is to help us understand the "moving parts" affected by a decision, and to help us to understand and quantify other

[85] Where appropriate, feedback would be treated as confidential. Respondents should mark relevant feedback as confidential as per the guidance set out in section 2 on"Your response, data and confidentiality".

assessments we make. We do not expect this modelling to perfectly replicate future conditions, but rather see it as an additional tool to support a qualitative decision.

5.40. Our consultants have been clear on the limitations of analysis (see Section 5 of their report). In particular, we would draw stakeholder's attention to the following limitations, assumptions and risks:

- Use of an agent-based approach. This approach seeks to replicate actual investor behaviours and dispatch decisions. This will not perfectly reflect the real world. However, since the model was commissioned by the Department of Energy and Climate Change[86] in 2010, it has been used extensively by Government and industry and has been central to a number of decisions and processes. We therefore do not have concerns and consider the limitations well understood.

- The EnVision model models dispatch and investment decision in the GB market and it allows for electricity flows across interconnectors in response to price signals from Europe. A simplifying assumption is that the interconnectors have the same carbon intensity as the nearest domestic generator within the GB merit order. We consider the approach taken is sufficiently accurate and proportionate to the needs of our decision.

- Other FES scenarios, notably 'Leading the Way', the scenario with the fastest decarbonisation, and 'System Transformation', which relies more on system than behavioural change, have not been modelled. As indicated, we think that the scenarios chosen are sufficient to illustrate the main mechanisms and impacts.

- Optimism Bias. The consultants' estimates rely on a smooth transition in contracts (supply, generation, existing CfDs etc.). It is possible that in the implementation of the modification, anticipated benefits are not as high as anticipated if any industry parties find a way to avoid passing savings through to consumers. Where relevant, such as in the case of CfDs, we have estimated the magnitude of the consumer risks.

[86] The predecessor to the Department for Business, Energy and Industrial Strategy ('BEIS')

- As of November 2021, global gas prices are extremely high, and this has led to a retail energy cost crisis. These current conditions in the energy market have greatly increased balancing costs. There has been no exploration of the impact on CMP308 if these conditions persist into the implementation period. Higher balancing costs might lead to greater BSUoS charges, which in the *status quo* arrangements would in turn lead to more significant differences in the costs faced by Large Generators and other generation that is not liable for BSUoS. This would lead togreater distortions to investment and dispatch. While this would be the case in the *status quo* arrangements, the current higher balancing costs and resulting BSUoS charges would present additional challenges for suppliers if CMP308 was approved, as the impacts would fall on demand. The distortions between generator types would not be present.

- We recognise that at a time of high gas prices, the case for investment in CCGT that is predicted by the model might not be seen, but we think the direction shown - that Large Generators may be at less of a disadvantage than in the current regime - is likely to hold true. We would expect the investment and dispatch impacts of the different BSUoS costs of Large Generators of other technologies, such as Wind or Solar and their non-liable counterparts to reduce.

Implementation Costs

5.41. We understand that the ESO also aims to implement CMP308 using a new ESO billing system to unlock process efficiencies. While CMP308 will increase charges on suppliers, given it is an increase in an existing charge we would not expect significant systems changes for industry. We address changes to CfD arrangements earlier in this document.

Hard-to-monetise costs and benefits

5.42. The monetised results do not represent the full impact that we expect to see from this change. We think this reform, if implemented, may have the following hard-to-monetise impacts:

- **Improved Generation Economics and Efficiency**: Removing BSUoS charges from Large Generators will reduce distortions in the signals faced by Large Generators, which we would expect to help in the delivery of more efficient markets, including flexibility markets. Better price signals will promote more efficient investments in the longer term.

On a more practical level, the removal of BSUoS charges from generators may reduce the burden on generators and developers and may free up resource allocated to BSUoS charges forecasting by large generators, potentially facilitating savings.

- **Energy System Resilience:** Our quantitative analysis indicates that the proposed reforms would have a significant impact on interconnector flows, with imports across interconnectors being displaced by Large Generators in GB once BSUoS charges are no longer levied on them. We consider that it is beneficial for the financial resilience of domestic generation it to be larger rather than artificially smaller due to a charging distortion.

- **System complexity**: No longer levying variable BSUoS charges on generators and having it feed into wholesale price bids will reduce system complexity, and complex interactivity. This may in itself help with system efficiency and contribute towards keeping bills down for consumers. Reduced system complexity may help more targeted policy measures to work effectively and make systemic risks easier to identify. This benefit may be amplified if CMP361, or a similar modification that removes BSUoS charge volatility is approved.

- **Transparency:** With approximately half of BSUoS costs no longer being passed through to consumers via wholesale prices and instead being charged to suppliers directly, the costs faced by consumers would be more transparent. It is not clear to consumers how much their suppliers have paid for BSUoS within their wholesale costs, as this would require knowing how much the generator concerns had built into their offers to account for BSUoS charges on export. In a large portfolio, this could be the average of a large number of purchases, each with different estimates. With all BSUoS charges falling on demand, users on fixed contracts may have a clearer view of the BSUoS costs built in, depending on the detail of the contract, while users with pass through contracts may see what has been built in in more detail or may get the direct costs with full transparency.

- **Other costs and benefits:** We understand that Large generators and suppliers (where the contract is not pass-through) build premiums into their offerings to account for uncertainty in the future cost of BSUoS charges. This is reasonable practice to account for uncertain future costs. With CMP308, generators will no longer need to build premiums into their wholesale offerings. We acknowledge that the effect of any inefficiencies due to transaction costs, forecasting costs and risk premiums associated with BSUoS charges being applied to large generators are difficult to capture. Following

CMP308, suppliers will need to take a view on a larger value of BSUoS costs. This may be further improved by CMP361, as, depending on the solutions developed, suppliers could have a more predictable, less volatile forward view of BSUoS charges. We will assess that modification separately in due course.

- **Supplier exposure to fluctuations in BSUoS charges:** Increasing exposure to BSUoS charges for suppliers under the CMP308 CUSC modification may present challenges, due to the greater costs that will fall on them. However, we do not see this as a greatly different role for suppliers – they are already required to forecast BSUoS charges in order to create their customer offerings. We invite feedback on whether suppliers may be better or worse placed to cope with fluctuations in BSUoS charge levels than the current model. CMP361, seeks to address this by delivering another key recommendation of the second BSUoS Task Force – fixing BSUoS charges in advance. Again, we will assess this in due course.

- **Remaining Distortions**: CMP308 does not address the benefits obtained by Behind The Meter Generation in offsetting demand BSUoS charges, but does mean exports from generation situated behind the meter pay BSUoS charges at the same zero rate as all other domestic generation types, improving competition for generation. We will continue to monitor this effect to ensure consumers are protected from any growing distortions.

Summary

5.43. The potential reform is expected to provide a benefit to GB consumers in the region of £320m Net Present Value in a Net Zero compliant scenario (or £370m NPV if progress on decarbonisation is slower), and so the energy system is made significantly more efficient. In effect, the market has been biased towards small distributed generation and energy imports and power emissions exported. Correction of the distortion leads to emissions rising in GB, though these are balanced by lower emissions in interconnected European markets. We note the carbon impacts of this modification are complex but estimate that it makes a positive contribution to reducing greenhouse gas emissions.

5.44. On its own, the modification has some non-monetised benefits in the areas of resilience, simplification and transparency. A small distortion would still remain to benefit Behind The Meter Generation, which can reduce demand BSUoS charges, and we aim to monitor this in case further engagement with industry on this issue is required. We consider these factors to be less important than the quantified consumer and system benefits but recognise the significance of the volatility issue to suppliers and end consumers, particularly in the context of high market prices.

6. Distributional analysis

Section summary

This section reports the distributional impacts of placing BSUoS charges solely on demand, particularly on end consumers but also on the impacts on other market participants such as suppliers, generators and CfD bidders. It takes into account different user archetypes including those that may be more common in the future and identified bill impacts, based on the static influence of BSUoS charge increases, and the dynamic influence of other changes such as reductions in the wholesale price.

Questions

16. Do you have views on the impacts of this proposal on end consumers, including large users and vulnerable users?
17. Do you agree with our assessment that reduced costs to generators are likely to feed through into lower wholesale prices?
18. Do you agree with our assessment that this policy will not have any significant material impacts on vulnerable users?
19. Do you agree with our assessment that this modification is unlikely to lead to any significant impacts on essential services or supply chains?

Overview of distributional effects

6.1. Our consultants' modelling sets out a full assessment of the impacts on a broad selection of consumer archetypes. These archetypes were first used in the impact assessment which we carried out as part of the TCR. This earlier framework has been expanded from simple views of annual and peak volumes to full half-hourly profiles, in order to properly capture the variable pricing of BSUoS charges.

6.2. Table 6 below summarises the archetypes considered. As with all archetypes, these are useful assessment tools but are not intended to cover the full range of possible customer profiles within all segments. For that reason, our consultants have also carried out qualitative assessments on specific segment impacts. The details of the specific profiles are not presented but a high-level summary is reproduced below. Overnight consumption is important, as those with a high overnight consumption face a greater impact from the increased BSUoS demand charge.

Table 5 - Net demand for each consumer archetype and the proportion of that user archetype's consumption which is consumed overnight

User group	Annual net demand (kWh)	Share of overnight consumption*
1. Domestic – Low consumption	1,800	21%
2. Domestic – Medium consumption	2,900	13%
3. Domestic – High consumption	4,300	16%
4. Domestic – High Economy 7	7,100	25%
5a. Domestic – Medium Solar PV	2,055	36%
5b. Domestic – Medium Solar PV with storage	1,148	43%
6. Domestic – Medium Electric vehicles	4,170	34%
7. Domestic – Heat pumps	5,447	21%
8. Commercial – Low consumption	10,000	9%
9. Commercial – High with onsite generation/storage	8,312	16%
10. Commercial – High without onsite generation/storage	25,000	10%
11. Commercial – Light industrial HV-connected	5,000,000	25%
12. Industrial - EHV-connected without onsite generation/demand management	50,000,000	33%
13. Industrial – T-connected without onsite generation/demand management	100,000,000	33%

Note: **The proposed change has the highest upward impact between 11pm and 7am (wholesale blocks 1 and 2) for the majority of scenarios at most points in the year. Hence customers who consume a disproportionate share of their energy during this time will see marginally worse impacts.*

6.3. As in the previous chapter, we have focussed on the results for the CT scenario[87] as it is compliant with GB's Net Zero commitments. Bill impacts can be separated into a static increase from BSUoS changes (shown in teal in the Figures below) and dynamic impacts after a number of other, usually offsetting, cost changes. The modelling suggests the net impact for individual network users from these reforms is relatively small, though it varies over time and depends on scenarios. For a domestic customer with low, medium or high consumption (1800kWh,

[87] Full detail on the distributional impacts for the SP scenarios is available in our consultants' report.

2900kWh and 4300kWh each year), our analysis suggests an expected annual increase of £0.59 and a reduction of £0.58 and £0.52 respectively once dynamic impacts are factored in.

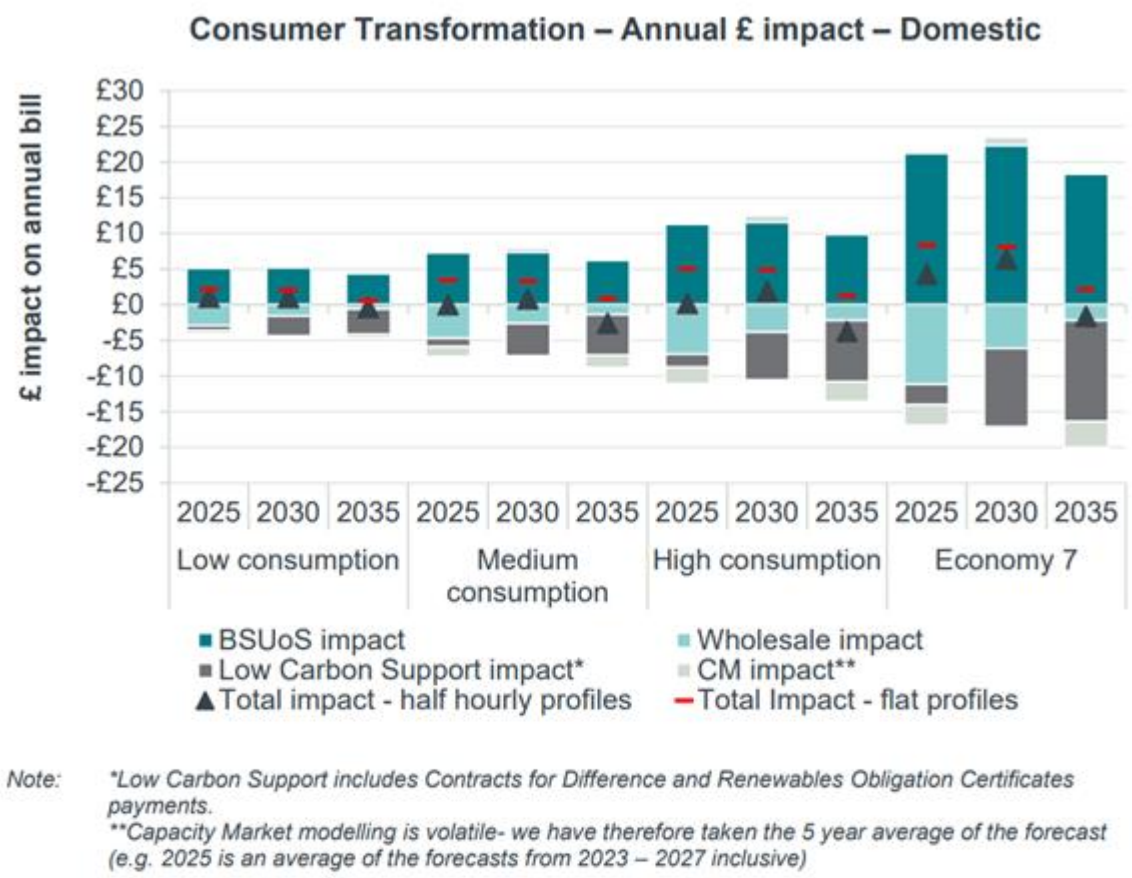

Figure 8 - Consumer Transformation – Annual £ impact – Domestic. Source: LCP/Frontier

6.4. As described above, as BSUoS charges are generally higher overnight, the largest increases in static annual BSUoS costs are faced by users with flat or night-weighted consumption profiles. One result of this is that domestic users with greater overnight usage, such as users with Economy 7 meters, with heat pumps or with electric vehicles are likely to pay more, but any effect is minimal once dynamic benefits are accounted for. For example, a high consumption Economy 7 user would pay about £3.00 extra each year (or as little as £0.07 each year in SP). An EV owner using 4,170kWh, with 34% overnight consumption, would pay just £2.46 more per annum (£0.47 in SP).

6.5. Our report highlights that all domestic low carbon technologies (LCT) increase the concentration of demand into the night period when BSUoS charges are highest driving a small increase in cost across domestic users with LCT. We would note that while these costs are small, they may be significant to some users, particularly if they are implemented alongside other increases, such as changes to the price cap.

6.6. For completeness, we note that this increased overnight cost effect may be addressed by the BSUoS Task Force's other key recommendation, which was that BSUoS charges should be set in advance and recovered as a flat and fixed, rather than variable volumetric charge. This is being progressed through a separate CUSC modification, CMP361, but we stress that this impact assessment makes no comment on that proposal and we will make our decision on that in due course as and when the proposal is submitted to us. Nothing in this consultation fetters our discretion with regards to that decision.

6.7. As noted above, Ofgem have a statutory duty to consider persons who:

- have a disability or are chronically sick;
- have a low income;
- are of pensionable age; or
- reside in rural areas.

6.8. These consumers sit across the usage spectrum. We would particularly note that our previous work for the Targeted Charging Review[88] suggested that individual household electricity consumption is a poor indicator of deprivation. Given the low estimated financial impacts on domestic users, and the fact that our archetypes span a very broad range of consumption, we do not consider this policy change to have a significant impact on vulnerable users. Though note that *when* electricity is used may be more relevant than annual consumption. Users of Economy 7 meters may be more likely to be off the gas grid or in rural areas, or may be more likely to be users that are taking steps to reduce their energy bills due to financial constraints. We would particularly welcome responses on whether adverse impacts might be expected on vulnerable users.

[88] See chapter 3 of our TCR Final Decision
https://www.ofgem.gov.uk/sites/default/files/docs/2019/12/full_decision_doc_updated.pdf

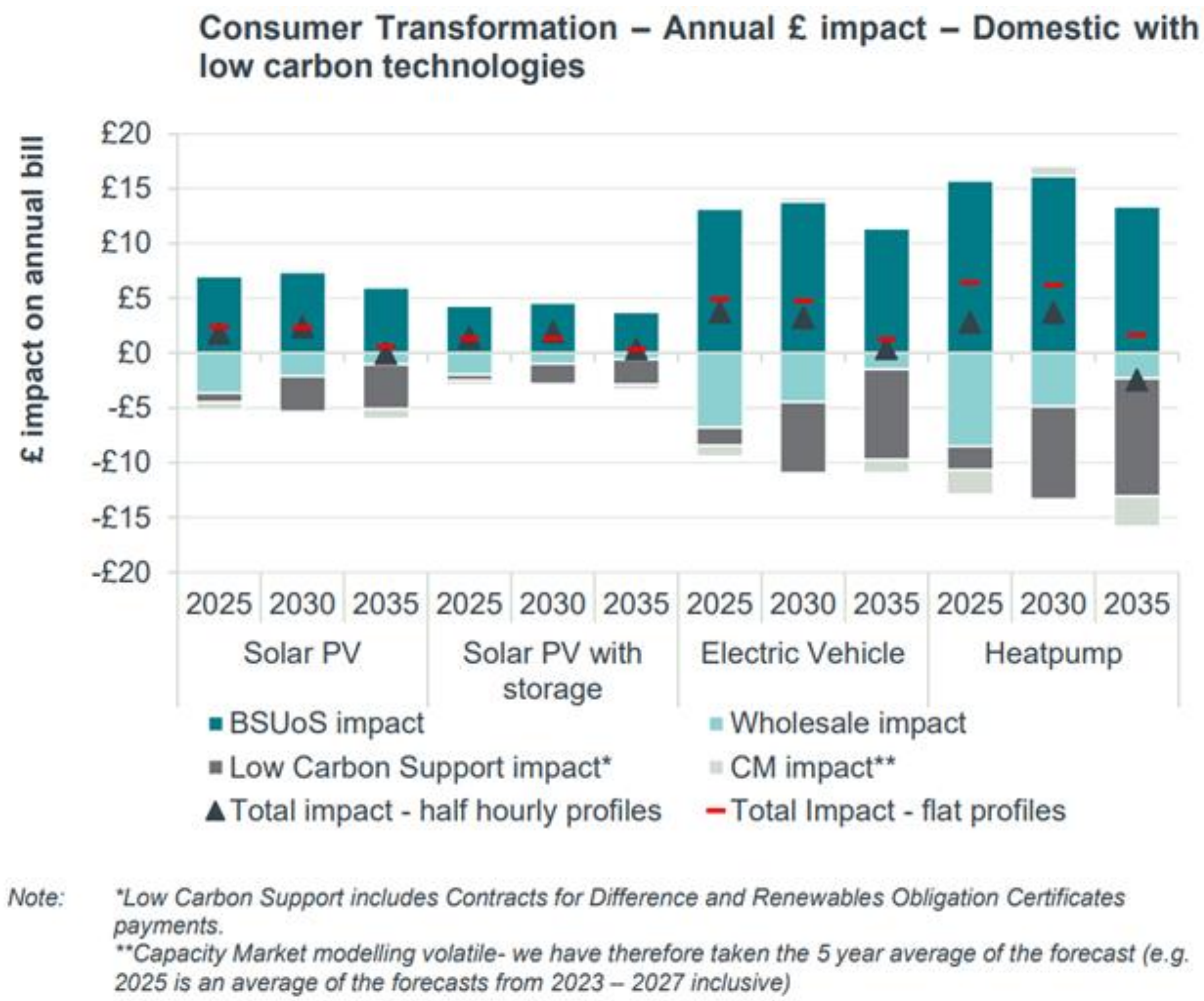

Figure 9 - Consumer Transformation - Annual £ impact - Domestic with low carbon technologies. Source: LCP/Frontier

6.9. An assessment of the impact on the bills of commercial customers is presented in 3.3.3 of the consultants' report accompanying this document. The static increase in the BSUoS charge element of bills ranges from £20 per year to £52 per year in the CT scenario as BSUoS is higher in this scenario. As commercial consumption profiles for these enterprises are skewed to the day, the dynamic impact of BSUoS charging changes result in a benefit of £2.04 per year for a small commercial user, £9.16 per year for a large commercial user without onsite generation and storage and £4.90 per year for a large user with onsite generation and storage. Were a flat profile adopted, annual costs would increase by £8.74, £21.84 and £7.26 respectively. Very broadly, the benefits of this change are linked to the volumes used, but also to the proportion used at night when BSUoS charges are expensive. This would not be the case for a flat volumetric charge like that proposed under CMP361.

6.10. Section 3.3.4 of the consultants' report deals with industrial customers charges but there is some compensation from offsetting savings. As might be expected, the shift of BSUoS to demand increases bills for these customers. Figure 9 shows the various factors affecting final bills for the CT scenario. The analysis suggests a light industrial HV-connected user with annual consumption of 5GWh might see an increase, taking into account all dynamic impacts such as lower wholesale costs, of around £2.3k in the CT scenario. This is an increase of c.£0.46/MWh (see Table 7 below).

6.11. A transmission-connected[89] user consuming 100GWh per annum might see an increase of c.£87k per year under the same scenario, or roughly £0.87/MWh increase. This is largely driven by the high night usage of these users (c.33%) and the very high volumes used[90]. Impacts in the Steady Progression scenario are much lower, with changes of just £56 per year (£0.01/MWh) for the HV users and £15,885 (£0.16/MWh) for the transmission-connected user.

[89] Here the archetype itself is for an example transmission connected user, rather than simply a Large generator.

[90] For context, in more typical market conditions where power costs average £40/MWh, a demand consumer using 100GWh per annum might expect to spend £4m per annum on wholesale electricity costs before policy or network costs are added.

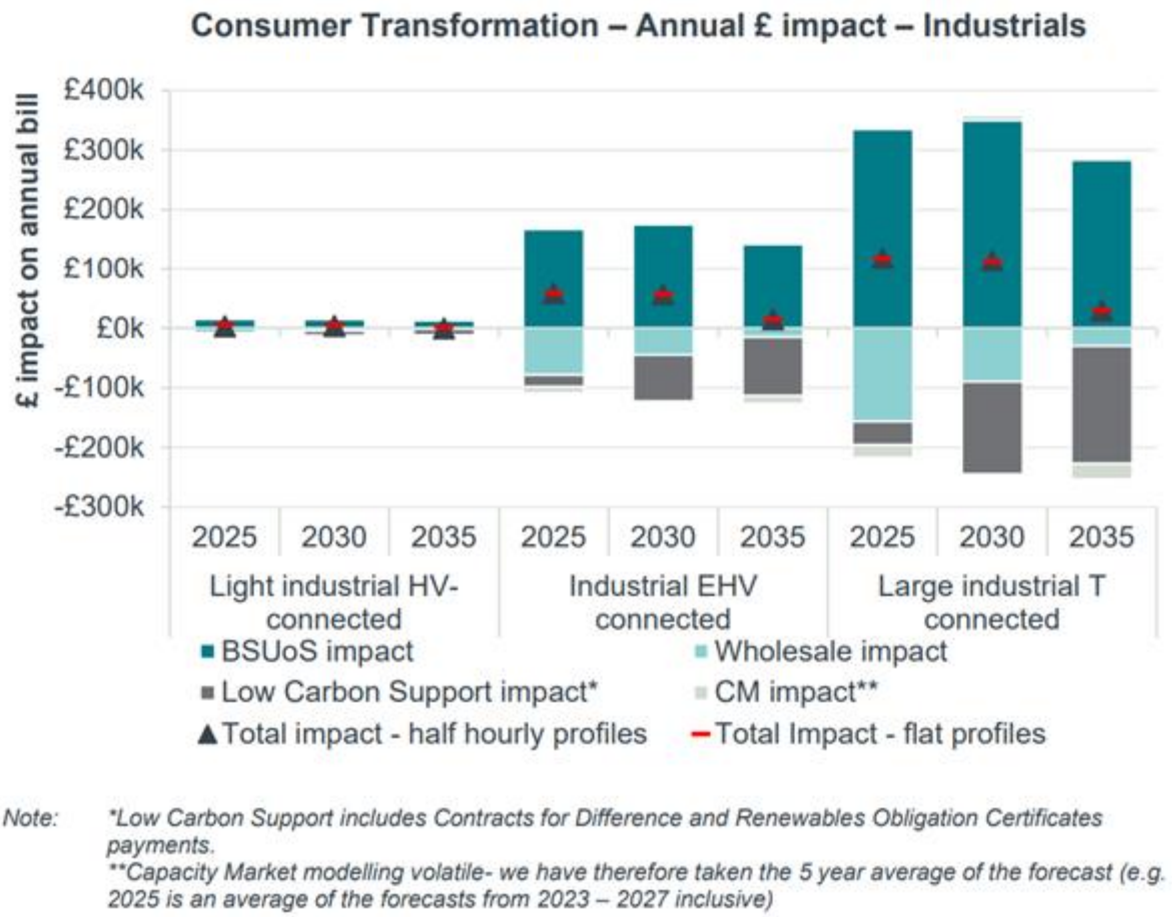

Figure 10 - Consumer Transformation - Annual £ impact – Industrials. Source: LCP/Frontier

6.12. Further information can be found within the consultants' report, as well as relevant discussions on the assumptions made and the limitations of the analysis. We would particularly like feedback on the assumptions used and our interpretation of the analysis.

Table 6 - Comparison of bill impacts from BSUoS charges and after dynamic impacts by large user category

Average 2025-35	**£/MWh**		
	Light industrial HV-connected	**Industrial EHV connected**	**Large Industrial T connected**
Profile assumption	More peak consumption than off-peak	Flat	Flat
BSUoS cost increase	2.85	3.23	3.23
After dynamic impacts bill increase	0.46	0.87	0.87

Impacts on specific industry groups

6.13. As described above, we consider our consultants' modelling of distributional impacts to be reasonably comprehensive though we recognise there are a number of user groups that warrant further consideration.

6.14. We recognise suppliers will need to build expectations of BSUoS charges into their offerings and will be buying power forward a number of years. While the work of the BSUoS Task Force has been well-signalled, it will not have been received and interpreted by all industry parties equally. It is reasonable to assume that suppliers may not all be able to immediately reflect changes to BSUoS charges in their tariffs, though we would expect a typical supplier to have considered the potential for changes in this area. Power that they have already bought may have BSUoS cost elements at some level built into the wholesale prices. Equally, fixed price tariffs are unlikely to have fully accounted for changes to BSUoS charges.

6.15. As a result, we think it is reasonable to assume that short lags between the changes and the full consumer benefits are possible. We recognise this may impact the benefits identified, which are estimated. We do not consider this possibility to undermine the proposal in the round but would welcome feedback from stakeholders on this point.

6.16. We note that generators who are planning to enter into future CfD auctions may need to factor different costs into their bids if this change is approved. Any delay in the removal of compensation mechanisms associated with BSUoS charges could lead to reductions in the benefits estimated, and that due to the details of the compensation process, there could be periods where BSUoS charges are entirely payable by demand but where compensation is still paid to some generators. We would also note, as set out in our wider systems modelling, pass through of generator cost reduction may not be complete. This may particularly be the case where the marginal generator does not face BSUoS charges. We address these issues in more detail in our earlier assessment section.

6.17. As noted above, we recognise that this modification would lead to the reallocation of costs to demand users at a time when many large and energy intensive users are under particular pressure due to energy costs. We consider that our modelling suggests this will not unduly add to end user costs, due to reductions in other energy system costs. We particularly welcome feedback from Large and energy intensive users (EII), including feedback on the additional risks that would sit with demand users if further proposed reforms, such as that put forward by CMP361, was not implemented.

6.18. We do not consider the cost impacts of this modification to be of the level of materiality where supply chain disruption could be expected. Firstly, this is a change that has been long expected and signalled, and one with a future implementation date. Secondly, we think the expected impacts on consumers is likely to be low, and more so if additional BSUoS charging reforms reduce the volatility of the charges. Nonetheless, we particularly welcome feedback from users from all sectors on the impact of the changes proposed where this may lead to:

- Impacts on critical national infrastructure or the provision of essential or public services;
- Impacts on manufacturing, chemicals or other key industries (including but not limited to EIIs);
- Impacts on logistics or transport sectors;
- Impacts on supply chains for the food, healthcare or hygiene sectors;
- Impacts on utilities such as waste, water treatment or recycling;
- Impacts on the natural gas, liquid fuel or electricity generation sectors;
- Impacts on non-traditional high-consuming industries such as data centres or electric vehicle charging stations.

7. Implementation

Section summary

This section covers implementation of this proposal. We are minded to implement this proposal on 1 April 2023, and below discuss some of the considerations around this.

Questions

20. We would note that increases in demand costs will need to be incorporated into the Price Cap methodology. Do you have any views on this area?
21. Do you agree with our proposed implementation date of 1 April 2023? Please provide your reasoning.

Implementation timing

7.1. The CMP308 Final Modification Report sets out the Workgroup's considerations as to whether the proposed implementation timescales are appropriate, and summarises the consultation responses received, a majority of which support implementation on 1 April 2023.

7.2. Some respondents gave their views that CMP361 and updating Ofgem's Price Cap methodology should be implemented at the same time as CMP308 to realise the full benefits of CMP308 and reduce risk for suppliers. Others expressed a preference that CMP308 is implemented on 1 April 2023 regardless.

7.3. We would note that a clear possibility of reform has been signalled to network users since the Task Force final report and our response in 2020. We note that Workgroup discussions also indicate that reform has been expected and "priced in" by some parties. We would therefore expect change to be priced into longer term contracts by some parties to some degree and have concerns that a different implementation date may lead to windfall gains and losses to market participants. We recognise that some Workgroup participants felt there was a risk that too short an implementation timeline may result in suppliers picking up BSUoS costs that have already been included in their wholesale costs for that period. In addition, some considered that suppliers might find that they have sold fixed price contracts, not factoring in additional BSUoS costs. We think April 2023 implementation provides a long enough transition to keep these effects to a minimum while ensuring consumers benefit from change swiftly, but welcome feedback from users on this and related issues.

7.4. Our December 2020 open letter agreed that April 2023 would be an appropriate target for the implementation of the Task Force's recommendation to recover BSUoS charges from Final Demand only and that remains our position.

Practical implications of implementation

Final Demand Data

7.5. Respondents to the Workgroup consultation noted the need for exemptions and declarations to allow the proposed treatment of Final Demand to work effectively. These discussions led to BSC modification P419 'Enhanced Reporting of Demand Data to the NETSO to facilitate BSUoS Reform' being raised. As of late 2021, this modification is progressing through the workgroup stage, having been combined with another data focused BSC modification, P395. We will assess these modifications against the relevant objectives in due course.

Residual Cashflow Reallocation Cashflow (RCRC)

7.6. The Task Force recommended the formation of a BSC issues group after the conclusion of the key BSUoS charging reform CUSC modifications to "implement Ofgem's decisions and investigate changes to the RCRC mechanism in light of the Task Force's recommendations". We would suggest that industry consider whether any changes need to be made to RCRC charging arrangements in the event we were to make a final decision approving this modification.

The Energy Price Cap

7.7. Changes to who is liable for BSUoS charges would flow through automatically under our current Energy Price Cap. The allowance in the cap for BSUoS charges would increase (reflecting the cost increase for suppliers), but this would likely be offset by decreases in the allowances for wholesale and low carbon policy costs. The overall effect should therefore be largely neutral, with expected benefits for consumers in aggregate, but we recognise the risk that some additional costs may fall on consumers by way of one of the other risks outlined in this document, or that there could be increased costs during the transition where contracts contain energy purchases made under the previous regime.

Ongoing monitoring and evaluation

7.8. As previously noted, it was the view of some industry participants that if this modification is implemented, monitoring is needed to assess whether the expected reduction in wholesale prices is equivalent to the additional cost of BSUoS charges to consumers and that consumers have not been disadvantaged by this modification. We note that our modelling did not indicate full pass through via wholesale prices – this was expected because Large Generators do not always set the marginal price in wholesale markets – but did show that consumer benefits were plausible due to reduced distortions. We also noted earlier in this document the presence of distortions concerning BTMG. We will continue to carefully monitor all market arrangements as per our duties to ensure consumers are protected, but do not propose specific monitoring arrangements related to this decision.

Implications of 2023 implementation on consumers

7.9. As noted above, we recognise that suppliers' customer offerings may include fixed elements that mean these changes will not be passed through, and that many suppliers will have agreed contracts of one, two or more years duration that extend beyond the implementation date of this modification. We also recognise they may have purchased power over periods that extend beyond this implementation date, which may have some element of BSUoS costs built in. We also note that the Workgroup materials for this modification confirm discussions were had on the specific issues around contracts.

7.10. We note that the AR4 CfD allocation round is scheduled to open in December 2021, with sealed bids expected in the period in late Q1 2022. We consider that a minded-to position now gives users useful additional information in the run up to this auction and we intend to progress our consultation and final decision as promptly as possible whilst ensuring parties have adequate time to provide representations in advance of any decision being taken.

7.11. We have considered whether further delay to implementation might be needed to ensure that charging changes do not have significant adverse impacts, particularly for vulnerable or large users. We do not expect such impacts, and consider 1 April 2023 to be a suitable date for implementation, but welcome feedback. We would equally ask for feedback on the impact of our proposed implementation timescales on supply chains and vital services.

Our minded-to position

7.12. On balance, we are minded to consider that 1 April 2023 implementation would be in the interest of consumers and welcome views from stakeholders on this.

8. Next Steps

Section summary

This consultation will be open until 19 January 2022, after which we will assess responses and consider whether any further engagement is necessary.

Questions

22. Do you have any other information which is relevant to this consultation?

Next steps

8.1. This consultation will be open until 19 January 2022. We will then assess any responses received, before publishing a decision on CMP308 if no further consultation is deemed necessary. We will publish separate decisions relating to the linked modification proposals referred to above.

8.2. We welcome other engagement from stakeholders, particularly where this enables them to make reasoned, informed representations within this process. Interested parties should contact the Ofgem representative named at the beginning of this document.

Appendices

Index

Appendix 1 – Privacy notice on consultations

Personal data

The following explains your rights and gives you the information you are entitled to under the General Data Protection Regulation (GDPR).

Note that this section only refers to your personal data (your name address and anything that could be used to identify you personally) not the content of your response to the consultation.

1. The identity of the controller and contact details of our Data Protection Officer

The Gas and Electricity Markets Authority is the controller, (for ease of reference, "Ofgem"). The Data Protection Officer can be contacted at dpo@ofgem.gov.uk

2. Why we are collecting your personal data

Your personal data is being collected as an essential part of the consultation process, so that we can contact you regarding your response and for statistical purposes. We may also use it to contact you about related matters.

3. Our legal basis for processing your personal data

As a public authority, the GDPR makes provision for Ofgem to process personal data as necessary for the effective performance of a task carried out in the public interest. i.e. a consultation.

4. With whom we will be sharing your personal data

We will not share your personal data with other organisations. We will publish non-confidential consultation responses, redacting any personal data that may be contained within them.

5. For how long we will keep your personal data, or criteria used to determine the retention period.

Your personal data will be held for one year after the project is closed.

6. Your rights

The data we are collecting is your personal data, and you have considerable say over what happens to it. You have the right to:

- know how we use your personal data
- access your personal data
- have personal data corrected if it is inaccurate or incomplete
- ask us to delete personal data when we no longer need it
- ask us to restrict how we process your data

- get your data from us and re-use it across other services
- object to certain ways we use your data
- be safeguarded against risks where decisions based on your data are taken entirely automatically
- tell us if we can share your information with 3rd parties
- tell us your preferred frequency, content and format of our communications with you
- to lodge a complaint with the independent Information Commissioner (ICO) if you think we are not handling your data fairly or in accordance with the law. You can contact the ICO at https://ico.org.uk/, or telephone 0303 123 1113.

7. Your personal data will not be sent overseas.

8. Your personal data will not be used for any automated decision making.

9. Your personal data will be stored in a secure government IT system.

10. More information For more information on how Ofgem processes your data, click on the link to our "Ofgem privacy promise".