Balancing Services Charges Task Force

Draft Report

02/05/2019

Contents

Foreword

Today we are publishing the outputs of the ESO-led Balancing Services Charges Task Force

This document is the culmination of three months of collaborative cross-industry work led by the ESO. It follows on from last year's publication of Ofgem's consultation on their Targeted Charging Review Significant Code Review and is a key next step related to this work programme.

The world of energy is changing around us; as our industry moves towards a smart, flexible, low carbon future this presents us with challenges, few more important than how we charge for our network services. The work of the Task Force has been to bring together a broad representation of the industry to consider our three key deliverables to help inform the next steps in Ofgem's network charging reform programmes.

Transparency has been the guiding principle for our Task Force and our aim has been to engage regularly and widely with the industry during this process. Building on these previous engagements, today we publish our draft report to give you the opportunity to provide your feedback on our work to date through this consultation.

Thank you in advance for your time – we are keen to hear your feedback and your views on what you read in this publication.

Colm Murphy
Electricity Market Change Delivery Manager
Electricity System Operator

How to read this document

This document is of relevance to a broad range of stakeholders who are interested in the future direction of Balancing Services Charges (BSUoS). The Task Force understands the industry might have limited time to review this document and therefore provides you with suggested ways to read this document depending on time available:

- **If you have 15 minutes**: read the 2-page executive summary.
- **If you have 1 hour**: read the 2-page executive summary, the summary of each Deliverable (Section 2.1, Section 3.1, Section 4.1) and the conclusion (Chapter 5).
- **If you have 2 hours**: read the full report.
    - Read in addition Appendix C if you want to learn more about the analysis performed.
    - Read in addition Appendix D if you want to learn more about the wider context.
- **If you prefer a presentation**: a webinar will take place on 7th May 2019. If you cannot make it, you can watch the recording and slides (information is available here).

Consultation

The following draft report of the Balancing Services Charges Task Force is published for consultation.

The Task Force welcomes industry views on the draft report. Responses are required by 17th May 2019 at 17:00.

The feedback received from the consultation will be considered in the final report of the Balancing Services Charges Task Force, expected 31st May 2019, and submitted to Ofgem.

If you have any questions about this document, please contact: chargingfutures@nationalgrideso.com.

Key Dates:

Consultation response deadline: 17th May 2019 at 17:00

Final report: 31st May 2019

How to respond to the consultation

The consultation period for this document is 10 working days. Responses should therefore be returned no later than 17th May 2019 at 17:00.

We appreciate that 10 working days is a relatively short consultation period, but this will enable us to publish our final report on the 31st May 2019 as per our Terms of Reference. The objective of the consultation on the draft report is for the Task Force to ensure the wider industry has the opportunity to review and provide feedback on the work and draft conclusions of the Task Force ahead of the final report being sent to Ofgem. The draft report does not propose any change to frameworks at this stage.

Responses should be submitted by replying to the consultation questions within the response proforma (available here) and e-mailing the proforma to chargingfutures@nationalgrideso.com. This will allow the Task Force to conduct an efficient review of all the response within the strict timescales.

We acknowledge that you may not wish elements of your response to be made publicly available or that, in the time available, you may not be able to provide a substantive consultation response. If so, responses should then be provided to Ofgem via TCR@ofgem.gov.uk at the earliest opportunity.

Consultation questions

The five consultations questions are stated below, highlighted through the draft report and also available in the response pro forma document. The Task Force welcomes all available rationale and evidence to support your responses, in particular if you don't agree with the Task Force draft conclusions.

1. Do you agree with the draft conclusion of the Task Force regarding Deliverable 1 (Y/N)? Please explain your rationale and provide evidence where possible.
2. Do you agree with the draft conclusion of the Task Force regarding Deliverable 2 (Y/N)? Please explain your rationale and provide evidence where possible.
3. Do you agree with the draft conclusion of the Task Force regarding Deliverable 3 (Y/N)? Please explain your rationale and provide evidence where possible.
4. Do you agree with the overall draft conclusion of the Task Force (Y/N)? Please explain your rationale and provide evidence where possible.
5. Do you have any other comments in relation to the draft report or draft conclusions of the Task Force?

Next steps

Following receipt of any responses to this consultation, the Task Force will review and publish a final report 31st May 2019, according to the Terms of References of the Task Force. The outcome of the consultation will be considered in the final report and submitted to Ofgem for further consideration.

Executive summary

Background to the Task Force

As the electricity system is changing, how the ESO operates the National Electricity Transmission System is also evolving. This points to the need for a change in the way which electricity networks are designed, operated and managed, with the aim to deliver greater consumer benefits. This might be achieved through a review of BSUoS charging arrangements.

Ofgem published their decision to launch a Balancing Services Charges Task Force on 28th November 2018. The overall objective of the Task Force is to provide analysis to support decisions on the future direction of BSUoS. BSUoS charges recover the costs of the balancing actions taken by the ESO when undertaking the day-to-day operation of the National Electricity Transmission System.

The Task Force is chaired by the ESO and Members were invited to join on the basis of their range of experience and to represent a broad range of industry viewpoints. The Task Force is working collaboratively and transparently to ensure that the wider industry is informed on how the Task Force progresses and is able to contribute to the Task Force work programme. All the information regarding the Task Force is available and updated regularly on the Charging Futures website here.

When considering the impact of their recommendations on the future direction of BSUoS, the Task Force recognises the need to consider the wider context (i.e. TNUoS, Targeted Charging Review SCR, Electricity Network Access Project SCR, other code modification workgroups, NOA process, connect and manage, Wider Access to the Balancing Mechanism, the Open Networks project, etc).

The Task Force followed a 3-deliverable approach to assess whether there is value in seeking to improve cost-reflective signals through BSUoS, or whether BSUoS should be treated as a cost-recovery charge.

Deliverable 1 - does BSUoS currently provide a useful forward-looking signal?

When assessing the current BSUoS charge, the Task Force found that it does not currently provide any useful forward-looking signal which influences user behaviour to improve the economic and efficient operation of the market. The Task Force identified five main reasons why this is the case: the current BSUoS charges are hard to forecast, complex, increasingly volatile, that other market signals are more material and so take precedence, and the current BSUoS charge applies to all chargeable users of the transmission system on an equal basis.

The Task Force also discussed the expected impact of BSUoS on the market and identified two effects. Firstly, market parties exposed to BSUoS are believed to be adding a risk premium to their costs to mitigate the risk of BSUoS uncertainty. Secondly, some parties might react to a subtle signal that appears overnight. Neither of these two impacts on the market result in behaviour that is of benefit to the system or ultimately to consumers.

Deliverable 2 - potential options for charging BSUoS differently, to be cost-reflective and provide a forward-looking signal

The Task Force then assessed whether individual elements of BSUoS have the potential for being charged more cost-reflectively and hence could provide a forward-looking signal. The Task Force identified four such potential options: locational transmission constraints; locational reactive and voltage constraints; response and reserve bands; and response and reserve utilisation. The Task Force discounted some other potential cost elements and so those are viewed to be cost-recovery.

The above assessment and conclusion of the Task Force has been shared with industry through various engagements and a Webinar on 7th March 2019 (available here). Stakeholder feedback reinforced the view of the Task Force as the industry present broadly agreed with the Task Force assessment of both Deliverable 1 and Deliverable 2. The Task Force received feedback that the analysis of the current BSUoS methodology is reasonable. Feedback also indicated overall support of considering these four potential options, and a belief that these options should be further explored under Deliverable 3.

Deliverable 3 - feasibility of charging potentially cost reflective elements of BSUoS to provide a forward-looking signal

The Task Force then assessed the feasibility of these four potential options to be charged more cost-reflectively and hence providing a forward-looking signal to then influence user behaviour in an effective manner. The Task Force used four evaluation criteria: the charging being cost-reflective; providing an effective signal; being practical and proportionate; and other considerations i.e. reflecting consumer needs, facilitating competition and/or innovation and being future-proof.

The Task Force concluded that whilst there are some theoretical advantages to all four potential options identified, the implementation of each of these would not or could not provide a cost-reflective and forward-looking signal that would drive efficient and effective market behaviour.

A significant limitation is that BSUoS is based on total costs incurred by the ESO, which can vary significantly. An effective forward-looking signal should be built from marginal costs rather than the total costs incurred by the ESO, so market parties face the cost they impose on the system. It is unclear how to achieve this through BSUoS, other than by some form of market splitting i.e. separating the Great Britain market into different zones with limited cross-zonal capacity for trading. Market splitting has however not been explored as it is out of scope of the Task Force.

Assuming a forward-looking BSUoS signal could be developed, another significant limitation is that this signal could be ineffective, as other signals are already in place through other market and charging arrangements (e.g. TNUoS, Balancing Mechanism and cash-out) so double-counting issues therefore arise. The main issue with double-counting is the risk of underestimation or overestimation, leading to market distorting signals.

In addition, allocating BSUoS costs to market parties responsible for these costs would be highly complex due to services being procured and used by the ESO based on complex assessments of the whole system (e.g. a party may be efficiently called once to cover a number of balancing issues, without being the single ‘cheapest’ option when considering those issues in isolation). Also, there is no evidence that the issues that exist currently (i.e. the charge being hard to forecast, complex, highly volatile, etc) will cease to apply in any of these potential options. Indeed, moving elements of charges to targeted groups of users may have the effect of making their charges more difficult to forecast, more complex and more volatile.

Draft Conclusion

Based on their work the Task Force therefore concluded that:

It is not feasible to charge any of the components of BSUoS in a more cost-reflective and forward-looking manner that would effectively influence user behaviour that would help the system and/or lower costs to customers. Therefore, the costs included within BSUoS should all be treated on a cost-recovery basis.

The Task Force believes that cost-recovery charges should aim to minimise market distorting signals, to benefit the system and ultimately consumers. However, the current construction of the charge may inadvertently send signals that are detrimental to the system. This should be considered by Ofgem and the industry in the future design of an effective cost-recovery mechanism for BSUoS. The structure of a BSUoS cost-recovery charge is out of scope of this Task Force.

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Introduction and Approach

1.1. Introduction

Draft Report

1.1.1 On 28th November 2018, Ofgem published their decision[1] to launch a Balancing Services Charges Task Force, led by the ESO and with the objective to provide analysis to support decisions on the future direction of BSUoS.

1.1.2 BSUoS charges recover the cost of day-to-day operation of the National Electricity Transmission System and depend on the balancing actions taken by the ESO and the associated costs of those actions.

1.1.3 The objective of the Task Force is to assess whether there is value in seeking to improve cost-reflective signals through BSUoS, or whether BSUoS should be treated as a cost-recovery charge.

1.1.4 The draft report provides the draft conclusions of the Task Force in relation to the three deliverables in Table 1, as defined by Ofgem in their decision to launch the Task Force.

Table 1: the three deliverables of the Task Force

	Deliverable
D1	Assessing the extent to which elements of balancing services charges currently provide a forward-looking signal that influences the behaviour of system users (Chapter 2)
D2	Assessing the potential for existing elements of balancing services charges to be charged more cost-reflectively and hence provide better forward-looking signals (Chapter 3)
D3	Assessing the feasibility of charging any identified potentially cost-reflective elements of balancing services charges on a forward-looking basis to influence user behaviour (Chapter 4)

[1] https://www.ofgem.gov.uk/system/files/docs/2018/11/decision_to_launch_a_balancing_services_charges_taskforce.pdf

1.2. Overview of the Task Force

Task Force organisation

1.2.1 The aim of the Task Force is to produce a report assessing the three deliverables as set by Ofgem and outlined in Table 1.

1.2.2 Task Force Members were invited to join on the basis of their range of experience and, while membership was limited, to represent a broad range of industry viewpoints. The list of the Task Force members is available in Table 2 below.

Table 2: Task Force members

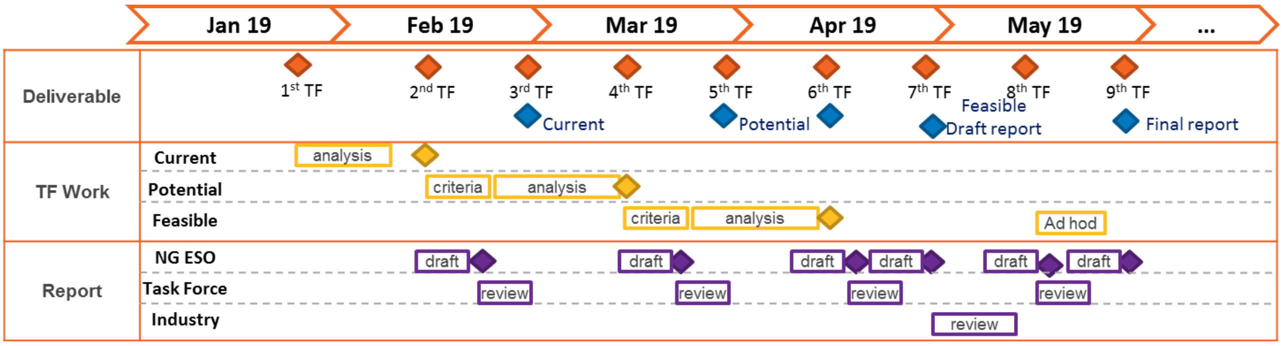
Name	Organisation
Colm Murphy (Chair)	National Grid ESO
Joseph Henry (Secretariat)	National Grid ESO
Sophie Van Caloen (Secretariat)	National Grid ESO
Tim Aldridge	Ofgem
Laurence Barrett	E.On
Nigel Bessant	Scottish and Southern Electricity Networks
David Bird	Octopus Investments
Caroline Bragg	The Association for Decentralised Energy
Tom Edwards	Cornwall Insight
Nicholas Gall	Solar Trade Association
Rob Hudson	Tata Chemicals Europe
Paul Jones	Uniper UK Ltd
James Kerr	Citizens Advice
George Moran	Centrica
Paul Mott	EDF Energy
Mike Oxenham	National Grid ESO
Dr Graham Pannell	RES
Grace Smith	Sembcorp Utilities
John Tindall	SSE PLC
Joseph Underwood	Energy UK
Lisa Waters	Waters Wye Associates

1.2.3 The Task Force is chaired by the ESO, which is stepping up in its role as a more independent ESO. The Secretariat role is also being undertaken by the ESO.

1.2.4 The full Terms of Reference of the Task Force are available here.

1.2.5 The initial work plan of the Task Force is detailed in the figure below.

Figure 1: Initial Task Force work plan



Engagement

1.2.6 The Task Force is working collaboratively and transparently to ensure that the wider industry is informed on how the Task Force progresses and is able to contribute to the Task Force work programme.

1.2.7 All the information regarding the Task Force is available and updated regularly on the Charging Futures website here. Any question or comment can be sent by email to chargingfutures@nationalgrideso.com and will be considered by the Task Force.

1.2.8 Since January 2019, wider engagement has taken place via a range of channels, such as the Charging Futures Forum, TCMF, DCMDG, the electricity operational forum, webinars and a consultation on the draft report. A list of engagement activities held to date is available in Appendix B.

1.3. Task Force Approach

List of elements of BSUoS

1.3.1 For the assessment, the Task Force identified a list of elements of BSUoS (as per Table 3). These elements are based on the Monthly Balancing Services Summary (MBSS) reports (more details available here), and each contributes differently to the total charge.

Table 3: Elements of BSUoS

Name	Description
Constraints (Transmission)	The costs incurred when there is a need to increase or decrease power flows from one part of the network to another part of the network due to a limit on the transmission network (i.e. the constraint).
Constraints (ROCOF)	The costs that arise from reducing the size of the largest possible infeed loss or bringing on more generation to increase the amount of inertia.
Response	A service used to keep the system frequency close to 50Hz. Fast acting generation and demand services are held in readiness to manage any fluctuation in the system frequency, which could be caused by a sudden loss of generation or demand.
Fast Reserve	This service provides the rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources. There are three categories: Firm Fast Reserve, Optional Fast Reserve and Optional Spin Generation.
Reactive	Management of voltage levels across the grid is needed to make sure it stays within operational standards and to avoid damage to transmission equipment. Voltage levels are controlled by reactive power, providers are paid to help manage voltage levels on the system by controlling the volume of reactive power that they absorb or generate.
STOR	Short-Term Operating Reserve (STOR) allows extra power to be held in reserve for when it is needed. It helps to meet extra demand at certain times of the day or if there is an unexpected drop in generation.
Operating Reserve	Positive Reserve is required to operate the transmission system securely, and provides the reserve energy required to meet the demand when there are shortfalls, due to demand changes or generation breakdowns. It is managed in the BM, through trades, or SO-SO services.
Constraints (AS)	Ancillary Services constraint costs including mandatory and commercial intertripping costs, where the ESO contracts ahead of time to manage a known transmission issue.
Black Start	Black Start would be used to restore power in the event of a total or partial shutdown. This is currently bilaterally contracted with power stations who can start and reenergise the system at the ESO's instruction.
Constraint (Voltage)	To access Reactive Power, a generator is sometimes required to be synchronised to the network. In this case, the energy from the generator is bought in order for the reactive power to be delivered.
Minor Components	Miscellaneous costs, such as BM actions not accounted for elsewhere or other general costs.
Other Reserves	Other reserves paid for through commercial contracts such as the demand turn-up service.

Negative Reserve	A Negative Reserve service can provide the flexibility to reduce generation or increase demand to ensure supply and demand are balanced.
Energy Imbalance	Energy imbalance is the difference between the amount of energy generated in real time, the amount of energy consumed during that same time, and the amount of energy sold ahead of the generation time for that specific time period. The monthly energy imbalance cost can be negative or positive depending whether the market was predominantly long or short.
ESO internal costs	The internal costs of operating the ESO in accordance with RIIO-T1, ESO Incentive Arrangements 2018-2021 and the Transmission Licence.

Definition of 'signal'

1.3.2 To ensure a common understanding in discussion the Task Force further clarified some of the considerations and terminology in relation to the Deliverables. The Task Force report will therefore use the definition in Table 4 below for "signal" and other related terms.

Table 4: Definitions of signals for the Task Force's report

	Definition
Signal	A market price which in theory could incentivise a party to do something. This does not necessarily have to be cost-reflective.
Cost-reflective signal	A signal that reflects an element of incremental system cost or benefit.
Useful forward-looking signal	A stronger test relating to the CUSC objective of "cost reflectivity", whereby if a party responded to the price signal, that "market behaviour" would be useful for reducing system cost. For example, it may not be useful if the incentive does not accurately reflect an incremental system cost or benefit, if it may point in the wrong direction, or it may overly incentivise behaviour if there is double counting because the behaviour may already be incentivised by a different mechanism.
Effective forward-looking signal	Strongest test relating to the CUSC objective of "effective competition" whereby users do actually respond to it in an effective way. For example, it may not be effective if users can't accurately forecast it, or there may be practical reasons why users can't, won't, or don't respond to it, or if parties which cause the same cost or benefit face different signals.
Market distorting signal	A signal to which users do respond to and which tends to result in sub-optimal market behaviour (potentially preventing other participants from delivering a more useful or more effective action) and therefore leading to a sub-optimal economic outcome i.e. increasing system cost. The signal may unfairly support or penalise market participants. For example, a signal may be a distortion if parties which cause the same cost or benefit face different signals, if the incentive is in the wrong direction, if it is double counting, or if it pollutes, masks or inappropriately counters the effect of other price signals.

1.3.3 It should also be noted that, by "market behaviour" the Task Force means any behaviour of industry parties which leads to the ESO taking different actions, resulting in different costs which reduce overall costs, or for other parties to take different actions which would then reduce overall costs. Market behaviour is therefore not understood as simply resulting in the same behaviour at a different price point.

1.3.4 The Task Force also identified two different types of forward-looking signals:

- Operational signal: a signal that influences generator decisions regarding dispatch, or incentivises customers to adjust their level of demand within day; and
- Investment signal: a signal that influences generator, or demand decisions regarding capital expenditure or decommissioning of assets.

1.3.5 Charges could provide operational or investment signals, but in economic theory those signals should be equivalent and lead to identical behaviour over a long period of time. The Task Force recognises the need to consider both effects, to be mindful of double-counting and unintended consequences.

BSUoS and the wider context

1.3.6 A brief overview of recent, ongoing and future developments which provide further context in relation to BSUoS and the work of the Task Force is available in Appendix D.

1.3.7 When considering the impact of their recommendations on the future direction of BSUoS, the Task Force recognises the need to consider the wider charging arrangements (i.e. TNUoS and DUoS) and ongoing review of those (e.g. Targeted Charging Review SCR, Electricity Network Access Project SCR and other code modification Workgroups such as CMP308). In addition, the Task Force is mindful of wider context, such as network planning (e.g. NOA process, connect and manage, etc) and other changes in the market (e.g. Wider Access to the Balancing Mechanism and the Open Networks project) are strongly interlinked with system operation and associated costs.

2

Deliverable 1

Assessing whether BSUoS currently provides a forward-looking signal that influences behaviour

2.1. Summary of Deliverable 1

2.1.1. Deliverable 1 was to assess which, if any, elements of balancing services charges currently provide a forward-looking signal that influences the behaviour of system users.

2.1.2. The draft conclusion of the Task Force regarding Deliverable 1 is as follows:

> The existing elements of BSUoS do not currently provide any forward-looking signal which influences user behaviour to improve the economic and efficient operation of the market. The signals some parties can forecast to an extent, i.e. from demand and/or wind, do not result in behaviour that would lower costs to consumers, and the volatility and inability to forecast BSUoS is adding risk premia costs to all parties exposed to BSUoS.

2.1.3. The Task Force assessed all elements of BSUoS (Section 2.2) and found that elements do not provide a useful forward-looking signal, and certainly not one which influences user behaviour in an economic and efficient manner. However, the Task Force noted that some signal could be provided during the overnight period. Also, constraint costs appear to be correlated with certain elements, i.e. high wind and low demand, but only to a certain extent. However, in each case, response from users may result in a less efficient, more costly resolution to system issues.

2.1.4. The Task Force has identified five main reasons why BSUoS does not currently provide a useful forward-looking signal (Section 2.3):

- The current BSUoS charges are hard to forecast and it has been shown that forecasted values by the ESO are not accurately reflecting the actual ex-post BSUoS;
- BSUoS charges are complex as they are an aggregation of various services with different drivers and commercial arrangements;
- BSUoS charges are increasingly volatile and it has been shown by the divergence of the 75% and 25% quartiles of BSUoS charges;
- Other market signals are more material, with BSUoS often relatively small compared to other signals currently provided by the market (e.g. wholesale prices); and
- The current BSUoS charges apply on an equal basis to all chargeable users of the transmission system irrespective of the nature (i.e. demand or generation) and the overall market response is therefore not efficient e.g. the effective responses of generation and demand would be different.

2.1.5. The Task Force also discussed the expected current impact of BSUoS on the market (Section 2.4). Two expected impacts were identified: the addition of risk premium by generators and/or suppliers to mitigate the risk of BSUoS uncertainty and the subtle signal overnight. Neither of these impacts on the market are of benefit to the system or ultimately to consumers.

2.1.6. The Task Force's initial conclusion has been shared with industry, in line with the engagement and communication plan. A Webinar, held on 7th March 2019, gathered the views of the wider industry and is available on the Charging Futures Website, here. The industry broadly agreed with the Task Force conclusion for Deliverable 1 at that time. Feedback from the Webinar is detailed in Appendix B and was considered when writing this draft report (Section 2.5).

Consultation question 1:

Do you agree with the draft conclusion of the Task Force regarding Deliverable 1 (Y/N)? Please explain your rationale and provide evidence where possible.

2.2. Discussion on each element of BSUoS for D1

Current charging methodology

2.2.2. The BSUoS charge is currently calculated as a flat tariff £/MWh per Settlement Period (HH - 30 minutes) and is applied proportionally to volume share, as follows:

$$BSUoS\ charge\ (£/MWh) = \frac{Half\ Hourly\ charge\ (£)}{Chargeable\ volume\ (MWh)}\ , for\ each\ settlement\ period\ (hh)$$

Where:

- Half Hourly charge: this is the cost of balancing actions taken that are allocated to that half-hourly settlement period.
- Chargeable volume: this is the total volume on the network in that HH.

2.2.3. BSUoS charges are calculated ex-post, based on a cost-recovery mechanism. This highlights the importance of the ability for market participants to forecast the charge for it to provide a signal. The ESO publishes BSUoS forecasts which are available here.

2.2.4. The BSUoS methodology, which is subject to change through the code modification process, is contained within Section 14 of the CUSC and can be found here.

Discussion on each element of BSUoS

2.2.5. Parties are being billed one BSUoS charge, which is an aggregation of all elements listed in Table 5 below. The Task Force therefore believes that market participants are likely to react on any signal provided by the total of the charge rather than on each component. For completeness, the Task Force however discussed each of the elements of BSUoS individually.

2.2.6. The discussion concluded that most elements do not currently provide any useful forward-looking signal. This is due to the various reasons highlighted below e.g. hard to forecast and complex.

2.2.7. After this discussion, there was some component grouping for the further assessments.

Table 5: Discussion on each element of BSUoS

Element	Discussion Notes
Constraints (Transmission)	Constraints costs are the biggest element of the BSUoS charges. The Task Force view is that it currently does not provide a useful signal as the costs are difficult to understand and there is a lack of visibility and forecastability of when constraints occur. Parties observed that at times high wind and low demand are correlated with high constraints costs, but only to a certain extent. There is a concern that "constrained off" plants can increase offer prices to make money from being constrained.
Constraints (ROCOF)	Currently no signal is provided mainly because the need for RoCoF is difficult to forecast and service despatch is opaque. The costs will depend on various elements and is expected to be dependent in some way on the generation mix.
Response	These costs are unpredictable, service use is opaque, and therefore are viewed to not provide a signal. Response costs are driven by a variety of reasons, often unplanned events.
Fast Reserve	No signal is thought to be provided as the cost is unpredictable and dispatch is not fully transparent. Some providers of reserves stated that, when being dispatched for Fast Reserves, they would be able to expect some impact on

	balancing services costs, but it did not alter their behaviour and no other parties knew they were being called for a service.
Reactive	A great part of the cost of Reactive Power is based on mandatory provision, but this is not fully transparent.
STOR	No signals are thought to be provided, as the cost is unpredictable and dispatch is not fully transparent.
Operating Reserve	No signal is thought to be provided, as the forecasting of those services is particularly difficult (used for various reasons) and its use is not transparent.
Constraints (AS)	Relatively small. Those costs largely depend on unplanned (and therefore unforecastable) events.
Black Start	No signal is provided currently by Black Start as those costs are relatively small and distributed between all settlement periods. The costs are known by the market, but parties cannot respond to flat fees/socialised costs.
Constraint (Voltage)	No signal is thought to be associated with voltage constraints.
Minor Components[2]	Relatively small.
Other Reserves	Relatively small.
Negative Reserve	Relatively small.
Energy Imbalance	Relatively small and currently a positive impact on overall costs.
ESO internal costs	Socialised costs that will not be impacted by behaviour of market parties.

Focused analysis of constraints costs

2.2.8. As part of the discussion detailed in Table 5, the Task Force noted that some signal could be provided by constraint costs as they seem to be correlated with certain elements, but only to a limited extent.

2.2.9. The Task Force performed a statistical multivariate analysis of constraints and non-constraints costs (more information in Appendix C.1) to examine possible correlation between those costs and other variables (i.e. wind, solar, demand, etc).

2.2.10. The result of the analysis for constraints costs identified some correlation with wind and demand, but each relatively low. The Task Force therefore looked at the shape of the relationship between constraints costs and those two variables and found that:

- There is some correlation between wind and constraint costs, with high wind typically being associated with higher constraint costs. However, the correlation is weak.
- There is some correlation between demand and constraint costs, with low demand typically being associated with higher constraint costs. However, the correlation is weak.
- In addition, there is a reinforcing effect when both wind is high and demand is low.

[2] The costs that are not easily accounted for in previous reported categories i.e. some BM actions, trading option fees, bank charges, sterling adjustments, non-delivery, etc.

2.2.11. It is worth highlighting that even if constraint costs can be explained partly by wind and demand data, this is only true to a limited extent[3], while the majority of constraint costs appear to be due to other factors, such as the availability of network capacity (see Appendix C.1). The Task Force believes that this can only provide a small signal to some specific users i.e. users that have this information and undertake this analysis on a regular basis to help inform and drive their behaviour. In addition, other reasons for BSUoS charges not providing a signal, such as difficulty to forecast and increasing volatility, remain valid and will be further explained in Section 2.3.

2.2.12. For completeness, the Task Force performed a similar analysis on non-constraints costs. The result of the analysis did not identify a significant correlation between those non-constraints costs and the variables (i.e. wind, solar and demand, etc).

[3] The R-squared - which is the percentage of the variance of costs explained by all explanatory variables i.e. wind, demand, etc - used to measure the correlation is 38% (20% and 18% for wind and demand respectively), which is still relatively weak.

2.3. BSUoS charges do not provide a useful signal

2.3.1. This Section explains in more detail, why the Task Force do not believe BSUoS is currently providing a forward-looking signal. Five main reasons have been identified, based on the Task Force discussions as well as engagement with the wider industry to date. The five reasons are:

- Reason 1: BSUoS charges are hard to forecast;
- Reason 2: BSUoS charges are complex;
- Reason 3: BSUoS charges are increasingly volatile;
- Reason 4: Other market elements take precedence over BSUoS charges; and
- Reason 5: BSUoS charges apply to all chargeable users of the transmission system on an equal basis.

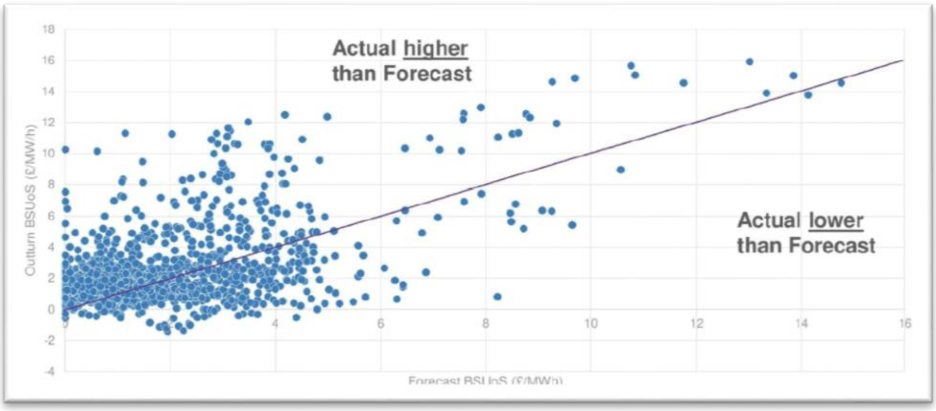
Reason 1: BSUoS charges are hard to forecast

2.3.2. Market parties currently react to BSUoS charges based on a forecast of the likely charge to be incurred on an ex-post basis, whether that be through a forecast provided by the ESO, their own forecasts, or a combination of both.

2.3.3. In order to have an efficient forward-looking signal based on forecasted charges, the ability to accurately forecast, half-hourly, is important. The Task Force understands that, to account for forecasting uncertainty, market participants include risk premia in their prices to account for what is viewed to be the unpredictable nature of BSUoS charges.

2.3.4. The difficulty of forecasting BSUoS charges as can be seen in Figure 2 below, which shows the numerous times where the charge per MW/h is materially over forecast or under forecast when the day ahead forecast charge is compared against the outturn charge.

Figure 2: actual versus forecast of BSUoS charges

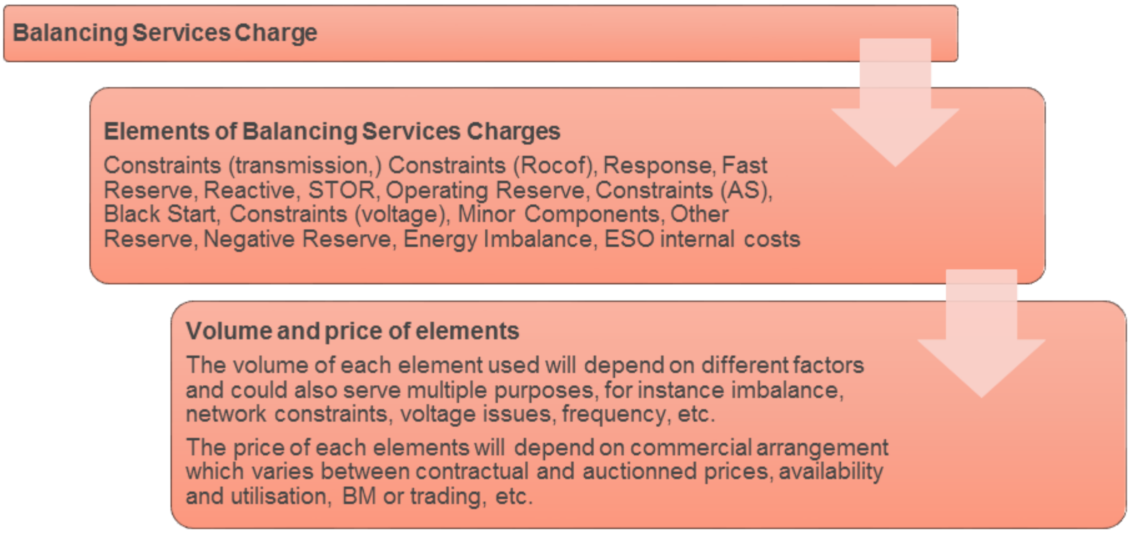


Source: A comparison of day-ahead forecast and outturn BSUoS charges per MW/h for December 2018.
Outturn Data: https://www.nationalgrideso.com/charging/balancing-services-use-system-bsuos-charges
Forecast Data: https://www.nationalgrideso.com/balancing-data/forecast-volumes-and-costs

Reason 2: BSUoS charges are complex

2.3.5. Market parties may not all understand the balancing services charge completely and that there is often an information asymmetry between market parties. The Task Force understands that the complexity of the charge structure and components of the charge (such as what a service might be called upon or what that might cost and the effect of the service called upon) adds to the challenge market parties face in accurately forecasting the charge.

Figure 3: Complexity of current BSUoS charges



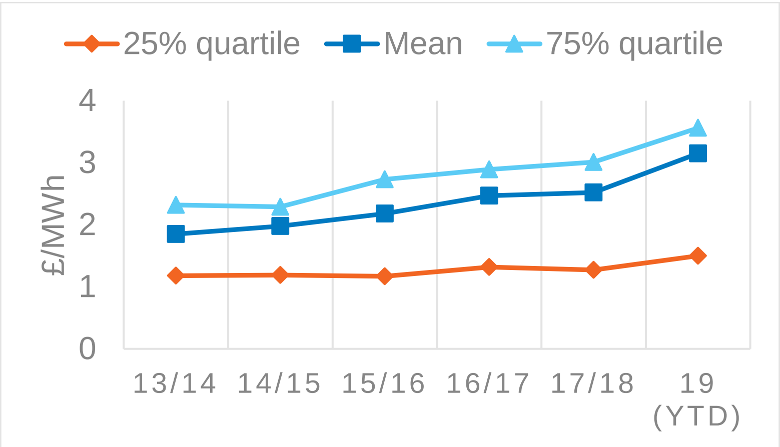
2.3.6. It is also worth noting that the ESO will take actions to solve issues arising on the National Electricity Transmission System in the most cost-effective way and this may sometimes add complexity. Most of the time, the ESO is following the merit order and taking the lowest-cost actions available to solve an issue. However, sometimes, a broader problem-solving approach leads to taking actions that will solve several issues, which only the ESO is likely to understand at the time. It is also possible that the ESO has to take another action e.g. if the generation that would have increased power output is located behind a constraint.

Reason 3: BSUoS charges are increasingly volatile

2.3.7. BSUoS charges are increasingly volatile, as evidenced by Figure 4 which shows that the mean £/MWh charge per settlement period is increasing and also that the 75% and 25% quartiles are diverging. These trends are expected to continue into the future due to changing system dynamics.

2.3.8. The Task Force understands that market parties find high volatility adds complexity to the provision of an accurate forecast.

Figure 4: Evolution of mean and volatility of BSUoS



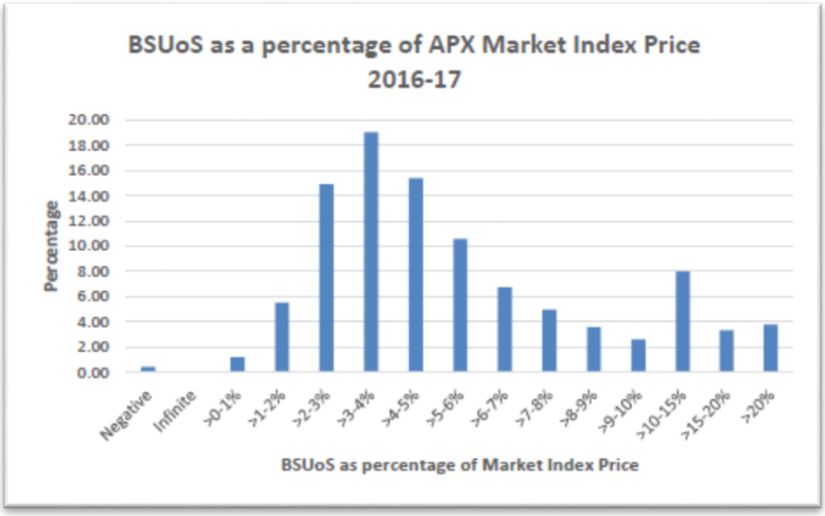
Source: Historic outturn £/MWh BSUoS charge for each SP.
Data: https://www.nationalgrideso.com/charging/balancing-services-use-system-bsuos-charges

Reason 4: Other market elements take precedence

2.3.9. The BSUoS charges are usually relatively small compared to other forward-looking signals provided in the market (e.g. wholesale market, capacity market, imbalance settlement price, etc). Market parties will therefore prioritise reacting to other signals and may decide not to change behaviour where there are stronger signals pulling in a different direction. For example, when BSUoS costs are expected to be high a generator is thought to be more likely to increase its prices in response, rather than avoid BSUoS by reducing or eliminating generation volume.

2.3.10. The Workgroup for CMP250[4] looked to compare the average cost of BSUoS to the average price of different wholesale power products. For example, the average cost of BSUoS in 2015 was £2.24/MWh and the average price of day ahead power in 2015 was £40.43/MWh. As such BSUoS constituted 5.54% of the average day ahead price for 2015.

Figure 5: BSUoS as a percentage of APX Market Index Price



Source: CMP250 Report https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc/modifications/cmp250-stabilising-bsuos-least-12-month

2.3.11. The Workgroup for CMP250 highlighted that BSUoS accounts for varying proportions of the wholesale energy price, in some periods a very large proportion. The data shows that BSUoS tends to lie in the region of between 2-6% of the power price for the majority of the time. However, it is not uncommon for BSUoS to represent much higher percentages of the power price, for example being greater than 20% of the power price over 3.5% of the time. This can occur where the power price falls significantly or where BSUoS charges are far greater than the average. In future, as intermittent renewables increase as a proportion of the generation mix, it is expected that BSUoS will account for an increasing proportion of the power price. When combined with volatility, this makes BSUoS an increasing issue for the parties trying to forecast the cost per half-hour.

2.3.12. Other factors, not directly related to electricity market price signals, are also expected to affect build and dispatch decisions of power plants. Those factors include: renewable incentives (e.g. Contracts for Differences, Renewable Obligation Certificates, Feed-In Tariffs); capacity market; and planning policy, etc. All these factors, to a greater and lesser extent, will affect the plant mix and the behaviour of parties.

[4] More information available in Appendix D and here: https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc/modifications/cmp250-stabilising-bsuos-least-12-month

2.3.13. Similarly, the majority of demand customers currently do not have the ability to react to BSUoS as a signal. This is mainly because demand usually does not have the visibility of BSUoS as a separate cost and therefore cannot react to it. Even when a customer is charged BSUoS as a separate cost, they might not react to it for other reasons. Indeed, for most demand, power is one of multiple running costs, so BSUoS charges are a relatively small part of their costs and decision-making drivers. For large or energy intensive customers who are more engaged with the power sector, there are costs associated with behaviour changes (opportunity costs, changing industrial processes, etc). Any reaction to a signal from BSUoS would have to be strong enough to overcome those other costs.

Reason 5: BSUoS charges apply to all chargeable users of the transmission system on an equal basis

2.3.14. The existing BSUoS charge is paid by users of the National Electricity Transmission System i.e. generators (including storage) and suppliers. Interconnectors have been exempt from paying BSUoS since 2012 due to European regulations.

2.3.15. The current methodology provides the same signal to both demand and generation and the Task Force believes this is not creating a useful forward-looking signal, since it will not drive the useful behaviour for all parties to reduce the system cost.

2.3.16. For instance, high BSUoS driven by constraints could dampen all activity at both sides of the constraint boundary, when it should incentivise/disincentivise generation/demand on each side of the constraint. In addition, in some circumstances dampening demand can further increase the BSUoS charge due to the effect of the reduced energy denominator in calculating BSUoS. The current methodology cannot drive behaviour that will benefit the system; rather, it could have the opposite effect.

2.4. Impact on market

2.4.1. The Task Force identified two areas where some impact of BSUoS could be expected:

- The current BSUoS methodology does lead to additional costs for consumers due to a risk premium; and
- Certain market participants can respond to a subtle signal when overnight BSUoS prices increases.

Both of these responses are not useful as they are likely to reduce the efficiency of the market and increase prices to customers.

Impact on market prices and risk premium

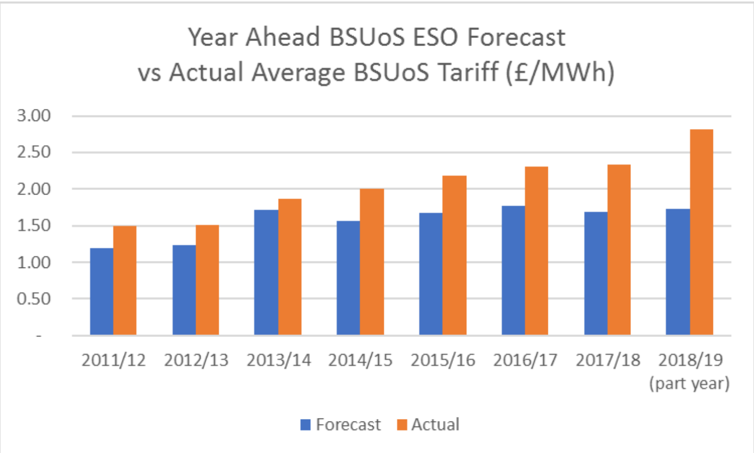
2.4.2. Parties reported that variability of balancing services costs is currently not identifiably reflected in the power price. In fact, high BSUoS costs are often seen at times of high wind whereas significant wind output depresses the wholesale price.

2.4.3. As discussed by the Workgroup for CMP308[5], there is little evidence that prices of short-term markets adjust as BSUoS varies (i.e. half-hourly volatility). This gives support to the theory that BSUoS is not a significant driver to short term power prices, although with wider changes such as in respect of increases in zero marginal cost output this dynamic could change in future.

2.4.4. The analysis also identifies that there are several products available on the market, in particular half-hourly products, where BSUoS half-hourly volatility could be reflected. However, it has been observed that the volume of APX half-hourly trades are small, so it is assumed that a risk premium must be added to prices as the way to manage the forecasting risk. The Task Force concluded that the majority of traded products effectively “smooth” BSUoS over a longer time period, via a risk premium. If this is correct then, in the long term, there will be adjustment of wholesale prices so that the long run average BSUoS costs are reflected in power prices.

2.4.5. In addition, Figure 6 below shows that over recent years the ESO has consistently under-forecast the annual average BSUoS price. As highlighted by the CMP250 Workgroup, if suppliers use the ESO forecast without applying a risk margin, they are potentially exposed. It was argued that larger companies are perhaps better able to take their own view of BSUoS prices, whereas smaller participants are more likely to take the ESO forecast at face value.

Figure 6: Year ahead average BSUoS forecast versus actual



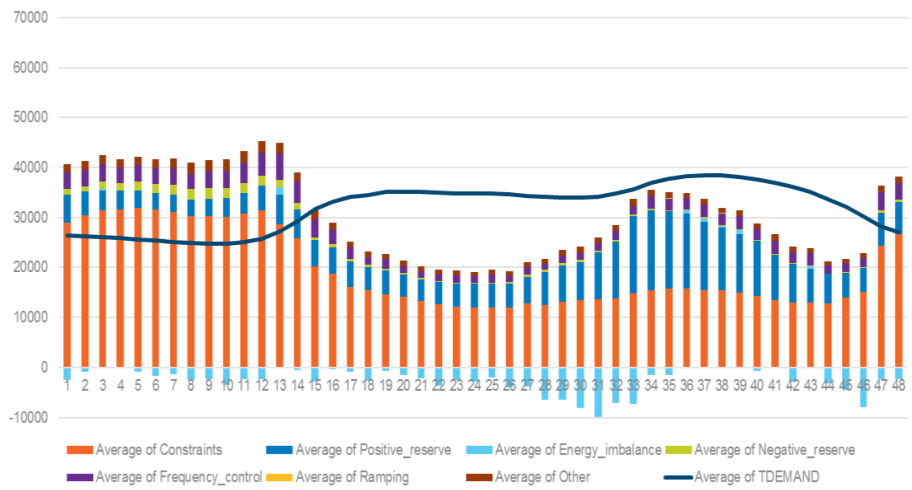
Source: Year ahead BSUoS forecast from ESO and actual BSUoS tariff

[5] More information available in Appendix D and here: https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc/modifications/cmp308-removal-bsuos-charges-generation

Overnight signal distortion

2.4.6. Figure 7 illustrates that high balancing services costs mainly occur overnight. Any further reduction in demand (potentially as a result of the higher BSUoS) will further drive higher BSUoS charges due to the “denominator factor” effect i.e. lower demand levels overnight divides the HH cost by less MWhs.

Figure 7: Average daily SP pattern of costs (£) of elements of BSUoS and Average Transmission Demand



Source: Costs (£) of elements of BSUoS (BM only) and demand (transmission system only)

2.4.7. The Task Force noted that signals occurring when the charge is higher are not adequate to create an efficient response. Indeed, they do not lead to a reduction of costs and instead may perversely increase costs to consumers by providing a signal to alter behaviour in a way which is unhelpful to network requirements e.g. by providing signal for demand to turn-down, which exacerbates the reduction of the denominator.

2.4.8. It is worth noting that it is unclear BSUoS was ever designed to provide a signal to the market, which may explain why any signal that might be inadvertently provided through BSUoS could lead to inefficient actions.

2.5. Industry feedback to date

2.5.1. The assessment and conclusion outlined in this chapter was shared with industry, in line with the engagement and communication plan, via a webinar on 7th March 2019 (available on the Charging Futures Website here). Feedback from the webinar is detailed in Appendix B.

2.5.2. In the main, stakeholder feedback at that time reinforced the view of the Task Force, highlighting that the complexity of BSUoS and difficulty in forecasting does indeed make it very difficult to influence user behaviour, as well as the problem of the charge being rolled into one and rather than being granular or locational. Some elements were also added to the initial analysis based on feedback e.g. reason 5 being that the charge applies to all chargeable users on and equal basis and is therefore not expected to be efficient.

2.5.3. The industry respondents to the relevant webinar question broadly agreed with the Task Force conclusion for Deliverable 1. The Task Force received feedback that the analysis is fair and that the existing elements of BSUoS do not provide a forward-looking signal.

3

Deliverable 2

Assessing the potential for BSUoS to be more cost-reflective and hence providing better forward-looking signals

3.1. Summary of Deliverable 2

3.1.1. Deliverable 2 is to assess the potential for existing elements of balancing services charges to be charged more cost-reflectively and hence provide better forward-looking signals.

3.1.2. The Task Force assessed whether BSUoS elements have the potential for being charged more cost-reflectively and hence could provide a forward-looking signal (Section 3.2). As a result of this assessment, the Task Force identified four potential options and discounted some other options. The Task Force also identified several common factors that could be applied across all potential options: knowledge of charge (ex-ante or ex-post) and granularity of charge (HH, daily, annual, etc).

3.1.3. The draft conclusion of the Task Force, in relation to Deliverable 2, is as follows.

> Four potential options have been identified by the Task Force as warranting further investigation regarding their potential to be charged in a more cost-reflective manner and provide forward-looking signals: (i) locational transmission constraints; (ii) locational reactive and voltage constraints; (iii) response and reserve bands; and (iv) response and reserve utilisation.

3.1.4. The above potential options of the Task Force have been shared with industry. A Webinar gathered views of wider industry (available on the Charging Futures Website here). Based on the feedback received, the Task Force proceeded with an assessment of the four potential options to determine the feasibility of each potential option. Feedback from the Webinar is detailed in Appendix B and was considered when writing this draft report (Section 3.3).

Consultation question 2:

Do you agree with the draft conclusion of the Task Force regarding Deliverable 2 (Y/N)? Please explain your rationale and provide evidence where possible.

3.2. Assessment of each element of BSUoS for D2

3.2.1. The approach taken under Deliverable 2 was to consider whether the existing elements of BSUoS have potential for being charged more cost-reflectively and hence could provide a better forward-looking signal. The assessment was undertaken as a qualitative exercise.

3.2.2. The Task Force identified potential advantages and limitations associated with the potential options, and these are considered as part of the feasibility assessment in Deliverable 3.

Potential Options Identified and Potential Options Discounted

3.2.3. For the assessment, each existing element of BSUoS were discussed by the Task Force but for ease of potential option development at that stage, elements of BSUoS were further grouped, e.g. ‘reserve’ might include various reserve products and costs.

3.2.4. The defining factor for the Task Force on whether options were provisionally identified or discounted was (i) whether the Task Force reasonably believed there was potential for each element to be charged more cost reflectively and (ii) whether the Task Force reasonably believed this could have potential to provide a better forward-looking signal.

3.2.5. Each of the four potential options provisionally identified by the Task Force are detailed in the table below.

Table 6: Potential options identified in Deliverable 2

Name	Description
Locational Transmission Constraints	A locational approach to Transmission Constraints for ESO actions and costs to resolve a constraint across identified system boundaries.
Locational Reactive and Voltage Constraints	A locational approach to Reactive and Voltage Constraints for ESO actions and costs to resolve reactive issues identified in a certain area.
Response and Reserve Bands	An approach where Response and Reserve costs are divided in different bands to reflect the needs created by different users.
Response and Reserve Utilisation	An approach where Response and Reserve utilisation costs are allocated to the user triggering the need for those services.

3.2.6. Each of the options discounted by the Task Force for progression into the feasibility stage under Deliverable 3 and the reason why are detailed in Table 7 below.

Table 7: Options discounted in Deliverable 2

Name	Reason
Black Start	The Task Force views these costs to effectively be insurance costs – whilst there are potentially options to make them slightly more cost-reflective, none of these options would appear to provide a better forward-looking signal.
ESO Internal Costs	Whilst there are potentially options to make these costs slightly more cost-reflective, none of these options would appear to provide better forward-looking signals to market participants.
Energy Imbalance	The Task Force view is that these costs cannot be further explored without consideration of cash-out and RCRC and the comparative costs/benefits to other existing elements of BSUoS charges are relatively small and therefore the Task Force deprioritised these costs.

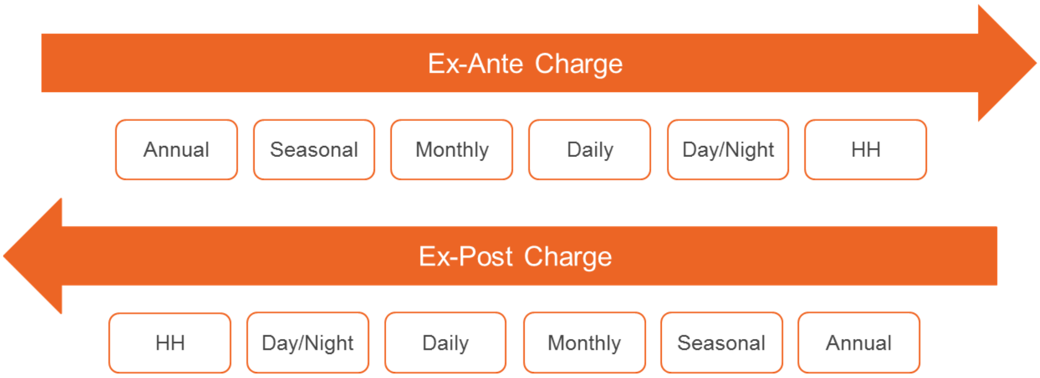
Elements of Response and Reserve	With the exception of those elements of these costs identified within the above Potential Options, the Task Force views these costs to effectively be insurance costs which cannot be made more cost-reflective and forward-looking to effectively influence user behaviour.

3.2.7. The Task Force recognises that there are various limitations that will arise with each of the potential options and these are further assessed in Chapter 4 (i.e. Deliverable 3).

Common Factors

3.2.8. The Task Force identified several common factors, defined as specificities that could apply to each of the potential options. These are shown in Figure 8 below, i.e. any option could be charged either ex-ante or ex-post with a different level of granularity in respect of time.

Figure 8: Common factors for potential options



3.2.9. Each of the common factors relating to knowledge (i.e. to when and over what period the price is known) is further explained as follows.

- Ex-ante: the charge would be set before the event based on a forecast or other calculation.
- Ex-post: the charge would be set after the event based on a defined methodology.

3.2.10. The common factors relating to time include different granularity of charge, like half-hourly, day/night, daily, monthly, seasonal or annual, etc.

3.2.11. It was also noted that the structure of the charge could possibly be changed (e.g. from being a £/MWh charge) and that the specific allocation of costs would need to be undertaken if any were to be identified as feasible.

3.3. Industry feedback to date

3.3.1. The Task Force had a provisional view on potential options for Deliverable 2, in line with the engagement and communication plan. A Webinar gathered views of the wider industry (available on the Charging Futures Website here). Feedback from the Webinar is detailed in Appendix B and was considered when writing this draft report as detailed below.

3.3.2. Feedback generally indicated overall support for the four potential options identified by the Task Force, and a belief that these options should be the focus of further exploration under Deliverable 3. There were some views to the contrary and some further suggestions on additional elements relating to potential options, such as a view that energy imbalance should be considered as a potential option.

3.3.3. Several comments were also raised regarding advantages and limitations of the potential options. These included feasibility issues with the potential options, links with TNUoS, and predictability through ex-ante charges. This feedback supports the work of the Task Force in the feasibility assessment for Deliverable 3.

3.3.4. Based on the mostly supportive feedback received on the webinar, the Task Force decided to proceed to Deliverable 3 with the four potential options it had identified.

4

Deliverable 3

Assessing the feasibility of charging potentially cost-reflective elements of BSUoS on a forward-looking basis to influence user behaviour

4.1. Summary of Deliverable 3

4.1.1. Deliverable 3 is to assess the feasibility of charging any identified potentially cost-reflective elements of balancing services charges on a forward-looking basis to positively influence user behaviour i.e. with the aim to reduce costs to consumers.

4.1.2. The Task Force had a theoretical discussion on some key elements to consider in the assessment (Section 4.2) with some input from Frontier Economics.

4.1.3. The Task Force agreed on a methodology (Section 4.3) in order to assess the feasibility of the four potential options identified in Deliverable 2. The Task Force used the following four evaluation criteria, which were based upon the Electricity Network Access Project SCR:

- Could arrangements provide a signal to parties in a cost-reflective manner?
- Could arrangements provide an effective signal to parties in a forward-looking manner?
- Are the changes practical and proportionate?
- Any other relevant consideration i.e. with regards to the needs of consumers, competition and/or innovation and/or barriers to entry and being future-proof?

For each of the above evaluation criteria, the Task Force used the 'Advantages, Limitations, Uniqueness and Overcoming limitations' (ALUO) model to facilitate the discussion.

4.1.4. The Task Force then assessed each of the four potential options identified in Deliverable 2 against the evaluation criteria: locational transmission constraints (Section 4.4), locational reactive and voltage constraints (Section 4.5), response and reserve bands (Section 4.6) and response and reserve utilisation (Section 4.7). Also, the Task Force discussed some other considerations (Section 4.8), as well as the potential link with TNUoS.

4.1.5. The draft conclusion of the Task Force, in relation to Deliverable 3, is as follows.

Whilst there are some theoretical advantages to all four potential options identified, the draft conclusion of the Task Force is that none of the potential options could feasibly provide a cost-reflective and forward-looking signal that drives efficient market behaviour to the benefit of consumers. Indeed, several limitations have been identified from the assessment of each of the potential options where no solution could be identified by the Task Force.

- BSUoS is based on total costs incurred by the ESO which can vary significantly. An effective forward-looking signal should be built from marginal costs rather than total costs, and it is unclear how to achieve this through BSUoS.
- Assuming an effective forward-looking BSUoS signal could be developed this signal could be ineffective as other signals are already in place through other market and charging arrangements (e.g. TNUoS, BM, cash-out), so double-counting issues arise.
- There is no evidence that the issues that exist currently (i.e. the charge being hard to forecast, complex, volatile, etc) will cease to apply under any of the potential options. Indeed, moving elements of BSUoS to targeted groups of users may have the effect of making charges harder to forecast, more volatile and complex for some parties.
- Allocating BSUoS costs to market parties responsible for these costs would be highly complex due to various reasons e.g. services are procured and used based on complex assessments of the whole system.

Consultation question 3:

Do you agree with the draft conclusion of the Task Force regarding Deliverable 3 (Y/N)? Please explain your rationale and provide evidence where possible.

4.2. Key elements to consider in the assessment

4.2.1. The Task Force had discussion around the key principles that should apply when assessing the potential options to be cost-reflective and providing a forward-looking signal. For this exercise, the Task Force also gathered the input from Frontier Economics (more information about their presentation to the Task Force can be found in Appendix E).

Marginal versus total costs

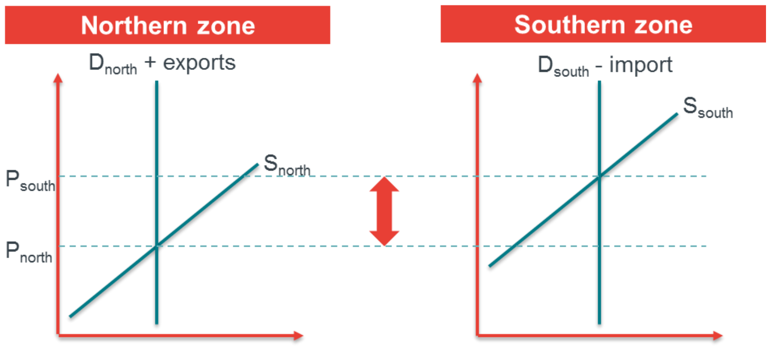
4.2.2. The Task Force view, aligned with Frontier Economics, is that cost-reflectivity should be understood to mean the charge is based on the marginal cost. This has also been highlighted by Ofgem in their 2017 TCR consultation as follows "Economic theory indicates that users will make the most efficient decisions about where, when and how to use the network when they are facing the incremental or marginal cost of their behaviour". The principle is that market participants should face the cost that they impose on the system.

4.2.3. However, the current BSUoS charging methodology is not based on marginal costs but on total costs. The ESO procurement and utilisation of any balancing services is based on an overall assessment of the total system. A charging methodology that is not based on marginal cost will not send efficient signals to the market. This will lead to a risk of the charge being underestimated or overestimated leading to a distortion in the market and limited benefits (or potentially creating additional costs) for consumers. Therefore, in order to create a forward-looking charge for BSUoS, an assessment of how the total BSUoS costs would change based on users' behaviour would need to be conducted to be able to determine the marginal cost. Such an assessment would have all of the same difficulties, if not more, than those faced with simply forecasting the total BSUoS costs.

4.2.4. The consideration of marginal costs can be illustrated using 'locational transmission constraints' as an example.

- Marginal costs in relation to congestion management can be reflected in zonal prices. A zonal price would be best defined in a situation where the market is split between different geographical zones with limited capacity available for electricity to flow between zones. In this case, an effective locational charge should mimic the marginal cost defined through market splitting i.e. separating the Great Britain market into different zones with limited cross-zonal capacity for trading. This is illustrated in the figure below.

Figure 9: Example of price signal across two different zones



Source: Frontier Economics (see Appendix E)

- However, there is no clear evidence that the cost of the balancing actions taken by the ESO would be reflected by a charge based on the zonal price. Indeed, when a constraint appears, the ESO faces costs for actions taken to ensure a safe operation of the total transmission network. There is no direct relation between this ESO cost and the marginal prices (or differences in marginal prices) that would appear in the case of zonal markets.

- It is unclear how feasible this approach will be. To correctly reflect the zonal price created by splitting the market, a very complicated model would need to be developed. This is a complicated way to achieve market splitting results and it is not clear that making such a change to the BSUoS methodology rather than implementing market splitting is the most appropriate way forward, if such an outcome was desired. Whilst market splitting has advantages and limitations, these have not been explored as this is considered out of the scope of this Task Force.
- It is worth noting that zonal pricing is one way of sending locational signals, based on a Short Run Marginal Cost but there are other ways of sending signals e.g. through the current TNUoS Long Run Marginal Cost, as is explained below.

4.2.5. This example demonstrates that any new charging methodology that is based on the allocation of the total cost rather than based on marginal costs is unlikely to lead to an efficiently developed system and benefits for consumers. In theory, it is possible to derive a forward-looking signal based on a model of likely system actions (e.g. mimicking market splitting for constraints costs) to provide an economic signal about system operation. This model would be complex and subjective, and it is unclear if such model could send an effective forward-looking signal. This model would not recover the revenue required to cover BSUoS costs.

4.2.6. As the costs of each element of BSUoS (transmission constraints, reactive, response, reserve, etc) are based on the costs incurred by the ESO to manage the total transmission network, the Task Force has highlighted that it is not effective to use the actual costs of system actions to construct a forward-looking marginal signal.

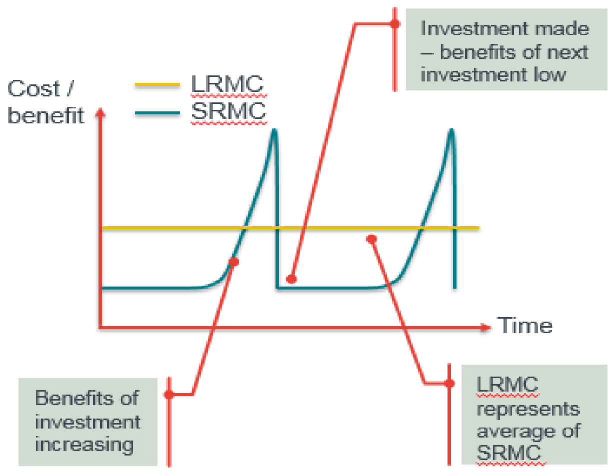
Double-counting issue

4.2.7. The Task Force, aligned with Frontier Economics views, then highlighted that, even if some forward-looking signal could be created through BSUoS, issues of double-counting might arise as illustrated in Figure 10 below.

4.2.8. Again, the consideration of double-counting issues can be illustrated using ‘locational transmission constraints’ as an example.

- The Great Britain market currently exhibits theoretically justifiable locational signals through Long Run Marginal Costs (LRMC) based on TNUoS charges. The only other theoretically justifiable basis for locational signals would be Short Run Marginal Costs (SRMC) based signals.
- However, having both SRMC and LRMC at the same time is counter-productive, as both aim to send an equivalent signal over time, but in a different way. Any new signal would therefore need to be ‘instead of’ rather than ‘as well as’ TNUoS charges.
- Therefore, if a SRMC signal is created, such as BSUoS mimicking market splitting prices, this will be double-counting with the existing locational signal provided by TNUoS and will therefore not be optimal.

Figure 10: Short and Long Run Marginal Costs



Source: Frontier Economics (see Appendix E)

4.2.9. The issue with double-counting is that it could lead to a suboptimal outcome, and therefore would not be beneficial for consumers. Indeed, in these cases, signals would not be effective as they will lead to a risk of the charge being underestimated or overestimated, leading to a market distorting signal. For instance, if the signal was stronger than it should be in certain locations which otherwise would have a lower signal to generate (for other reasons such as lower fuel costs), this may result in reduced investment in generation in these areas. Instead, the market would build generation in other places. Overall, the impact on consumers would be a higher cost than they would otherwise have faced.

4.2.10. The issue of double-counting arises for the 'locational transmission constraints' option with the signal provided by TNUoS but also for others potential options i.e. for 'response and reserve utilisation' with the signal provided by the imbalance price (where some response and reserve costs, as well as scarcity values, are used in the calculation).

Existing limitations are expected to remain and might be exacerbated

4.2.11. The Task Force also highlighted that the existing five limitations discussed in Deliverable 1 will remain and might be exacerbated: the current BSUoS charges are hard to forecast, complex, increasingly volatile, that other market signals are more material and so take precedence, and the current BSUoS charge applies to all chargeable users of the transmission system on an equal basis.

4.2.12. The Task Force believes that isolating elements of the BSUoS charge and allocating them to more targeted groups of users is not expected to improve predictability as disaggregating and reapportioning the cost of ESO actions would not be a task stakeholders could reasonably forecast. As highlighted in Deliverable 1, while some correlation could be identified between constraint costs and wind and demand, this is only true to a relatively small extent. Volatility could also be exacerbated as costs and parties are more targeted.

4.2.13. Additional complexity and lack of clarity will also arise due to: difficulties identifying the specific cause related to the ESO actions; how to allocate the costs of the ESO to a specific cause; and how to identify the parties causing the need for ESO actions, etc.

4.2.14. This means that (as per the conclusions of Deliverable 1) any of the identified potential options are unlikely to be able to provide an effective forward-looking market signal and unlikely to influence user behaviour to the benefit of the system and consumers.

4.3. Assessment methodology

Evaluation criteria

4.3.1. To assess the feasibility of charging potentially cost-reflective elements on a forward-looking basis to influence user behaviour, the Task Force used four evaluation criteria as detailed in Table 8 below. The criteria were developed partly based on the Access and Forward-Looking Charges SCR criteria, which is also looking at forward-looking charges.

Table 8: Criteria for feasibility assessment of potential option

Name	Description
C1: Could arrangements provide a signal to parties in a cost-reflective manner?	For example: could the cost be targeted according to the 'polluter pays' principle? Is the charge cost-reflective i.e. based on marginal cost?
C2: Could arrangements provide an effective signal to parties in a forward-looking manner?	For example: are they expected to be reasonably predictable to provide a signal? Are there any conflict or risk of double-counting with existing signals?
C3: Are the changes practical and proportionate?	For example: are the expected costs of the change proportionate to the consumer benefits? Can changes be implemented given applicable legislative frameworks and/or other policy areas e.g. decarbonisation? Are they expected to be simple and/or costs to the consumer? Can customers respond if they see a signal?
C4: Any other relevant consideration?	This evaluation criteria includes: - Consideration of the needs of consumers for an essential service. For example: do the changes recognise the needs and concerns of domestic/industrial consumers? - Consideration of the impact on competition and/or innovation and/or barriers to entry. For example: are the changes expecting to increase market competition? - Consideration with regards to being future-proof. For example: are the changes relevant in relation to changes to generation mix and/or peak demand and/or through settlement reform, etc.

ALUO Model

4.3.2. The ALUO Model is a facilitation process/technique to generate options against a problem or question being asked. It enables to take those options and refine them to attempt to find an effective solution to any problem or question.

4.3.3. For each of the options which have been generated the Task Force then considered:

- the <u>Advantages</u> of each option proposed;
- the <u>Limitations</u> each option;
- the <u>Uniqueness</u> each idea brings to the table; and
- Potential solutions to <u>Overcoming Limitations</u>. Note that, the Task Force could not always find a way to overcome limitations. Therefore, unless stated, it should be understood that no overcoming solution could be identified.

4.4. Assessment of 'locational transmission constraints'

4.4.1. In Deliverable 2 (Section 3) 'locational transmission constraints' was summarised as follows: 'A locational approach to Transmission Constraints for ESO actions and costs to resolve a constraint across identified system boundaries.'

4.4.2. In support of the Task Force discussion on locational transmission constraints a simplified two-zone model was created. The description of the two-zone model is available in Appendix C.2. It highlights some of the options for charging transmission constraint costs on a more locational basis, alongside how balancing charges on a £/MWh basis could change.

Summary of 'locational transmission constraints'

4.4.3. Whilst there are some theoretical advantages to 'locational transmission constraints' and some of the identified limitations could potentially be overcome, the draft conclusion of the Task Force is that the implementation of this option would not provide a cost-reflective and forward-looking signal that drives efficient market behaviour. The main arguments are as follows:

- A fundamental issue that arises is that the constraints costs are not based on the marginal costs but on the total costs incurred by the ESO. The only way to provide an effective signal would be to implement market splitting but this is out of scope of this Task Force.
- Even if some forward-looking signal could be created, it will not be optimal as it will be double-counting with the existing location signal provided by TNUoS.
- The implementation of locational transmission constraints would raise several limitations to provide a cost-reflective signal. For instance, issues will arise when identifying the cause of the constraints due to high complexity of the system.
- The existing five limitations discussed in Deliverable 1 will remain and might be exacerbated.

Detailed option evaluation 'locational transmission constraints'

C1: Could arrangements provide a signal to parties in a cost-reflective manner?

4.4.4. **<u>Advantages and Uniqueness</u>**

4.4.4.1. The Task Force identified some theoretical advantages if the charge could be allocated more locally to be more targeted towards market parties causing or exacerbating the constraints costs.

4.4.4.2. They also noted some correlation in Deliverable 1 regarding constraints costs, there might be potential for this element of BSUoS to be used more cost-reflectively.

4.4.5. **<u>Limitations and Overcoming Limitations</u>**

4.4.5.1. <u>Correlation does not imply causation.</u> Although the Task Force identified in Deliverable 1 some correlation between some of the variables (i.e. high wind and low demand) and transmission constraint costs, the correlation identified is relatively weak. This highlights that the majority of constraint volumes appear to be due to other factors, such as the availability of network capacity.

4.4.5.2. <u>Complexity of the cause of a constraint</u>. The cause of any constraint may be due to a combination of factors such as total generation behind a system constraint being higher than forecast, total demand behind a system constraint being lower than forecast, insufficient reinforcement of network capacity and/or reduced network availability due to network outages. It is important to consider the different causes to avoid double charging. For example, if a user has paid TNUoS to access the network, it may not be appropriate to charge the user again for constraints caused by the network company choosing not to reinforce the network, or if network is not available due to an outage. Therefore, the Task

Force questioned if it is practically possible to adequately identify the causes of individual constraints for charging purposes.

4.4.5.3. ESO actions based on local and wider system issues. The ESO might sometimes take more expensive actions due to the lowest-cost action not being viable (i.e. due to another constraint on the system or to avoid the creation of another issue or to solve multiple issues i.e. a single more expensive action to solve two issues in parallel might be more economic than two separate actions to separately solve those issues. The ESO may also take balancing actions (and incur balancing costs) in one time period to address an issue in another time period e.g. to proactively but efficiently resolve a future issue. Therefore, the Task Force view is that it would not be possible to charge market parties for the additional costs in a targeted manner in such circumstances. Multiple-issue actions may be challenging to disaggregate and reallocate to specific issues for the purposes of targeting a charge. In all of these examples, the resulting cost incurred by the ESO (as allocated to one element of the balancing total) could not be reasonably forecastable by users and therefore could not become an effective signal.

Further to the above, if there are multiple causes of a constraint, multiple potential solutions to solve a constraint and that actions which solve a constraint could also potentially solve other system issues and vice versa, the Task Force questioned whether it is possible to 'correctly' target a cost to the 'correct' market participants(s) under a locational transmission constraints model.

4.4.5.4. Constraint costs are total costs and not marginal costs. Even if the cause of constraints could be adequately identified, issues arise to allocate those costs in a cost-reflective way i.e. based on marginal costs. As discussed in Section 4.2, an effective cost-reflective charge should be based on marginal costs. The only way to have such a signal would be to mimic a market splitting situation. But the costs of constraints are the costs of actions taken by the ESO, which depends on the volume and price of units to be redispatch. This is not directly related to the total amount of generation and demand behind each constraint.

Overcoming Limitations. This limitation could only be overcome by moving towards market splitting (or creating a signal that mimics it). However, there are other advantages and disadvantages with this option and it is out of scope of the work of the Task Force.

4.4.5.5. Expanding chargeable parties. There was discussion in the Task Force on the appropriateness of expanding the charging base to include interconnectors and/or TOs, due to the impact such parties can have on the costs associated with transmission constraints.

Any option containing the concept of expanding the chargeable base to include Interconnectors and/or TOs would require careful consideration in respect of unintended impacts. For example, allocating the cost of constraints to TOs could have implications for double counting TO incentives as part of the RIIO process which could undermine the NOA process and incentivise overinvestment in infrastructure. Additionally, an expected limitation with such option would be the requirement for significant legislative and licence change (including in respect of price controls).

Overcoming Limitations. With regard to TOs, there will likely be opportunity to further consider as part of the ongoing RIIO-2 development process i.e. in relation to network availability obligations or incentives associated with their Network Access Policies.

4.4.5.6. Link with BM actions. In the event of there being no change to charging for BSUoS charges on a per MWh basis, a user exacerbating a constraint (at least in the case of generation) might be paid through the BM to alleviate a constraint. With locational transmission constraints, the other users would face increased costs whilst the example user alleviating the constraint through the BM would not face such increased costs. The example user was however exacerbating the constraint, prior to action being taken by ESO. Therefore, the Task Force questioned if it would be possible to charge all polluters on a targeted basis.

Overcoming Limitations. This limitation could be overcome by moving away from a per MWh charge. However, as volume is important in relation to management of constraints, it is unlikely to be feasible.

C2: Could arrangements provide an effective signal to parties in a forward-looking manner and are they expected to drive useful market behaviour?

4.4.6. Advantages and Uniqueness

4.4.6.1. A targeted price signal to market parties behind a constraint could in theory reduce the volume and cost of constraints action in the Balancing Mechanism by influencing parties on one or both sides of a constraint to take action in the interests of the system and consumers. This could especially apply to truly incremental demand i.e. to existing demand which could be taken in a less constrained time period.

4.4.7. Limitations and Overcoming Limitations

4.4.7.1. Double-counting with TNUoS. It is argued that locational signals for both generation and demand are already fully accounted for in TNUoS (as the long-term cost efficiently incurred should on average equate to the short-run cost) in respect of network charges and that any locational elements within BSUoS would therefore be double counting for network charging purposes. Indeed, TNUoS already provides a locational investment signal to both demand and generation with the purpose of reflecting the incremental constraint cost caused by parties which may be manifested in the network companies' decisions to either incur cost to reinforce the network, or incur constraint costs. Any locational elements within BSUoS would therefore be double counting for network charging purposes.

As explained in Section 4.2, in economic theory, both short and long-run market charges will send a similar signal over time, but in a different way. While both signals could be efficient, there is no logic to implement both.

Overcoming Limitations. Any move towards locational transmission constraints would require a review of network changing arrangements because (for generation) the TNUoS Year-Round element and (for demand) the locational £/kW element already reflect incremental costs which networks choose to incur via either reinforcement, or constraints. In order to prevent double counting of the constraint cost investment signal, TNUoS charges would arguably first need to be correspondingly reduced. However, this may not be practical, or proportionate.

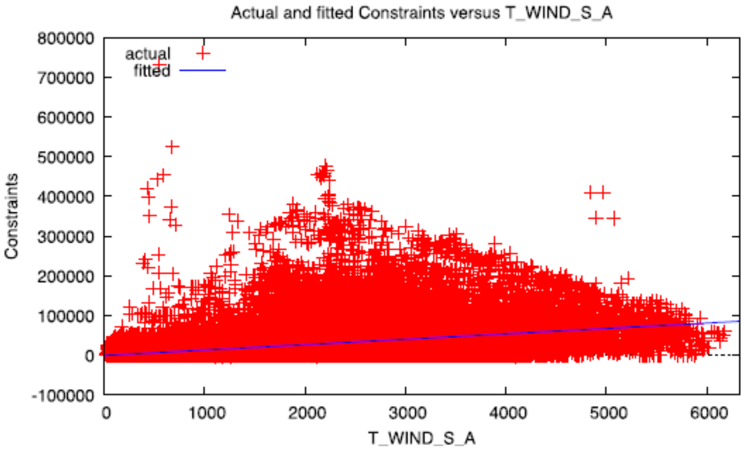
It might also be possible to simply transfer the costs associated with all transmission constraints from BSUoS into TNUoS total but this might lead to other issues as discussed further in the report (Section 4.8).

4.4.7.2. Charge Predictability, Complexity and Volatility. Under Deliverable 1 it was demonstrated that three of the contributing reasons to BSUoS charges currently not providing a forward-looking signal which influences user behaviour are a lack of predictability, complexity and increased volatility. These issues would remain in respect of locational transmission constraints and, in all likelihood, would be enhanced as it is expected that the reasons for the lack of predictability and complexity would remain and that costs for transmission constraints are likely to be more volatile than many other components of BSUoS.

Therefore, an expected limitation is that market parties (or ESO) will likely have difficulty forecasting any locational transmission constraints charge. If users relied on their own forecasts of what the outturn BSUoS price was likely to be, then the merit order of dispatch would become a function of their own forecast errors instead of genuine economic fundamentals. This may even result in parties taking actions in opposite directions which cancel each other out.

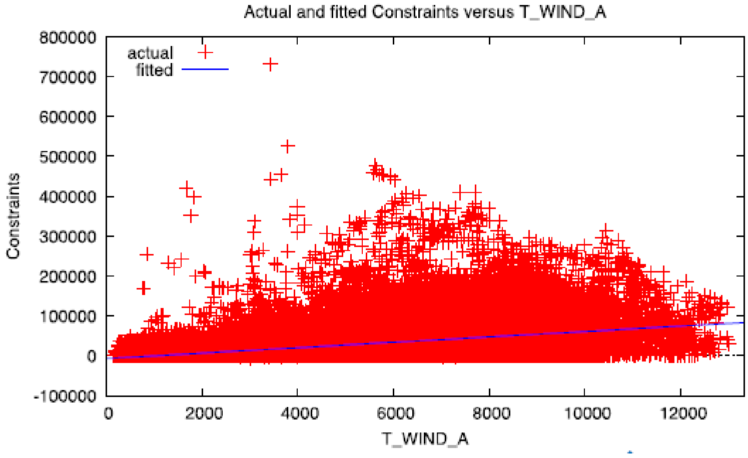
Figures 11 and 12 below illustrate this by considering the correlation between wind and constraint costs at a more granular level (i.e. for Scottish wind). It shows that the correlation does not improve when considering a more locational variable (i.e. Scottish wind).

Figure 11: Correlation between constraints costs and Scottish wind[6] (R-squared 0.166412)



Source: Costs (£) of constraints (BM only) and total Scottish wind

Figure 12: Correlation between constraints costs and total wind (R-squared 0.196177)



Source: Costs (£) of constraints (BM only) and total wind

Overcoming Limitations. In theory, it could be possible to overcome this limitation with greater data transparency and to a certain extent (e.g. through forecasting improvements) but practically a way of fully overcoming this limitation was not identified by the Task Force.

4.4.7.3. Trade-off between constraints costs and network investment. The Task Force discussed the inherent trade-off made by network companies (including through NOA) of the balance between investment in infrastructure and constraint costs.

Constraint costs will gradually increase to the point at which it becomes more efficient to reinforce the network to avoid further constraint costs. Various factors influence this decision including the MWs connected to and taken from the network. For example, it is expected that the commissioning of the Western Link will have reduced constraints costs. In a locational transmission charging model, this might have reduced the charges for Scottish generators in some cases but this would have been outside of their control.

More importantly, it could be argued that the ESO Network Options Assessment process should mean that constraint costs under the existing regime are being efficiently incurred in the long-run and that factors outside the control of market participants could always arise.

[6] Scottish wind data is based on BM wind and an ESO forecast of non-BM wind.

4.4.7.4. Conflict with BM signal. The Balancing Mechanism already provides an economically efficient signal regarding dispatch for the management of constraints to some generation and demand, albeit much of the demand is currently unable to independently participate. If a BSUoS dispatch signal were applied as well, this would arguably be double counting which would pollute the BM price signal and lead to a less economically efficient outcome.

If BSUoS was applied as a constraint price signal, then parties would take into account the BSUoS price in their Balancing Mechanism bid prices. This would distort the merit order in the Balancing Mechanism because the BSUoS price signal would either be not cost reflective (because it was set too far in advance), or uncertain (because it is set ex-post forcing users to rely on their own individual forecast of what it will be). This would likely result in Balancing Mechanism actions being taken out of economic merit resulting in a less efficient operational dispatch and a higher total system cost.

By using a BSUoS price signal to manage constraint costs, the ESO would become a price setter and volume taker. By contrast in the current Balancing Mechanism, the ESO is a volume setter and price taker. It is important to consider which of these approaches is likely to result in the most economically efficient operational actions at lowest system cost. If BSUoS were used as a price signal to incentivise operational dispatch to mitigate a constraint, then the party setting the price, such as the ESO will not know in advance how much volume will respond to a given price signal. This means it is possible that the market could over respond to a price signal resulting in the ESO having to take otherwise unnecessary action in the Balancing Mechanism to compensate.

This issue would also result in out of merit operational dispatch decisions for all other Balancing Mechanism services including energy balancing.

Overcoming Limitations. These limitations could potentially be overcome through either unifying both the short-run and then long-run marginal costs into a single charging methodology or through some form of market splitting whereby the costs of locational transmission constraints are priced into the wholesale market price or potentially a zonal imbalance price. However, it would be important to consider whether this may be practical, or proportionate and this is outside of the scope of the Task Force.

4.4.7.5. The price signal could be indeterminate. If a BSUoS price signal was calculated on an ex-post basis, then users would need to take operational decisions based on their forecast of what the outturn constraint price is likely to be, but if such an action resulted in no constraint taking place, then there would be no price signal. This means that even if users could accurately forecast what the price of a constraint may be, they would not be able to accurately forecast whether a constraint would actually occur, so whether the constraint price would actually apply. If users are unable to accurately forecast if a constraint will take place, then they will not be able to respond in an economically efficient way. This approach contrasts with the current Balancing Mechanism approach whereby the ESO dispatches users only if and when they are actually required to manage a constraint.

4.4.7.6. Precedence of other market signals. Even with locational transmission constraints being targeted on a polluter pays basis to generation and/or demand identified as exacerbating a constraint, it is expected that (notwithstanding other feasibility issues) additional costs or benefits associated with such a charging redistribution would not be sharp enough to result in a change in user behaviour which would benefit the system or consumers.

To demonstrate this point, the Task Force has taken the illustrative two-zone model as described in Appendix C.2. Through some assumptions about user behaviour, whilst in some of the models there is some potential for some of the parties to benefit, the expected benefit would be at such a level that other market signals would likely continue to take precedence for a significant amount of the time.

4.4.7.7. Ex-ante versus ex-post. An expected limitation is that neither ex-ante nor ex-post charging are likely to result in the creation of an effective forward-looking market signal and so unlikely to influence user behaviour to the benefit of the system and so consumers.

However, notwithstanding the above, there are further considerations in respect of the difference between an ex-ante charge and an ex-post charge which merit consideration:

- The Task Force view is that ex-post charges will not provide an effective signal for locational transmission constraints if users cannot respond to them. In addition, based upon previous analysis in Deliverable 1, an ex-post charge is likely to be very difficult for users to accurately forecast and so users will not likely be able to respond to it efficiently. This is exacerbated by the inability to hedge the charge and so risk premia become a factor. This contrasts with the existing Balancing Mechanism approach where the ESO is able to select balancing actions from an economically efficient merit order in real time in response to system requirements as they arise.
- The Task Force view was that ex-ante charges for locational transmission constraints would be economically inefficient because the magnitude and timing of constraint costs are very difficult to forecast in advance. Therefore, an ex-ante charge is unlikely to be cost-reflective. Forecast error regarding the charge would result in users incentivised to dispatch out of economic merit at times when there may be no constraint reason to do so. This approach would also likely introduce a reconciliation process to address over or under recovery due to forecasting errors.

There would be a trade-off between cost reflectivity and effectiveness as a price signal. If the price were set in advance, then users would be better placed to take action in response to it, but the signal would be subject to forecast error from the ESO, so would not be cost reflective. However, if the signal were provided close to delivery, or on an ex-post basis, then the charge could be more cost reflective, but users would have to take decisions in advance based on their own forecast of the charge was likely to be, which would make it a less effective signal.

The key difference between the two approaches is who is forecasting and who is best placed to take on forecasting risk - in the event that an ex-ante approach to charging were to be implemented in future then further consideration would also be required in respect of ESO risks and funding arrangements.

C3: Are the changes practical and proportionate?

4.4.8. **Advantages and Uniqueness**

4.4.8.1. If demand positively responds to an effective signal, this would support greater generation volumes from low carbon technologies which would support decarbonisation.

4.4.9. **Limitations and Overcoming Limitations**

4.4.9.1. Multi-zone complexity. In reality, the system is more complex than the two-zone model as described in Appendix C.2. In a complex system with multiple interconnections and constraints it may be prohibitively complicated to determine who is on the "right" and "wrong" side of a constraint as well as determining whether all market parties on one side of a constraint are equal and should face the same signals. It is therefore questionable whether market participants can be expected to reasonably understand the potential or likely ESO actions to resolve a constraint in advance.

Overcoming Limitations. This limitation could potentially be overcome with much greater real-time data transparency although this may only be partially overcome even with full transparency due to the expertise required to understand the system to a level which would allow market parties to predict the actions of the ESO in advance.

4.4.9.2. Different Generation and Demand metering zones. The geographic and electrical location at which transmission-connected generators, and some embedded generation is easy to determine. However, the location of demand and some embedded generation is not, as this is currently metered based on a GSP Group. GSP groups will not necessarily align with a constrained boundary so any option which involves targeting the cost of constraints to demand will likely require changes to metering/grouping arrangements so that demand either side of a constraint within a particular GSP Group can be separated into demand helping and exacerbating the issue.

Overcoming Limitations. This limitation could potentially be overcome by changes to metering/grouping arrangements so that demand either side of a constraint could be identified for the purpose of charging market parties in a more targeted manner in respect of locational transmission constraints.

4.4.9.3. Connect and Manage. SLC C26.6 of the Transmission Licence 'use of system charges resulting from transmission constraints costs are treated by the licensee such that the effect of their recovery is shared on an equal per MWh basis by all parties liable for use of system charges'. It is understood that these stipulations originated due to Government policy (in the form of a Public Service Obligation) in respect of the implementation of Connect and Manage in Summer 2010. This means that any changes to either the sharing on costs associated with transmission constraints on an equal basis and/or a MWh basis would likely contravene these requirements.

Overcoming Limitations. This limitation could likely be overcome by changes to previous Government policy in respect of Connect and Manage and a subsequent change to the Transmission Licence.

4.4.9.4. Inconsistency with access arrangements. Current access arrangements for transmission connected generators involve users paying a network charge in return for financially firm access whereby if users do not receive the access product they have paid for, then the user is compensated. Locational transmission constraints would penalise generators for times when they have paid for access to the system. This would be inconsistent with arrangements for current access rights. This inconsistency extends to access arrangements for demand where there are no (non-physical) restrictions placed on demand in respect of access so long as access is paid for in accordance with the calculations in respect of TNUoS for Demand.

Overcoming Limitations. Any move towards locational transmission constraints would require a review of other network changing arrangements.

4.4.9.5. Incremental charging. Charging on (or charging differently for) incremental actions in response to any signal was expected to be a limitation with any option containing the concept of incremental capacity and how incremental capacity could actually be accurately demonstrated. For example, for reductions in generation or increases of demand outside of the BM (or through an ancillary service contract with ESO) how could the incremental capacity which has benefitted the transmission constraint be differentiated from reductions in generation or increases in demand which would have naturally happened.

4.4.9.6. Less flexible market parties. The Task Force considered who might be able to react to any signal provided and so an expected limitation with any option which relates to locational transmission constraints is that (depending on to whom the charge and how the signal is targeted) less flexible demand and generation could see distributional cost increases. For example, energy intensive industries or baseload plant could face higher costs if they were to be charged a higher £MW/h rate on a socialised basis as under some of the illustrative models in Appendix C.2.

Overcoming Limitations. It would be possible to alter the signal or the charge (such as negative charging for incremental demand) but such alterations also have limitations.

C4: Any other relevant consideration?

4.4.10. Advantages and Uniqueness

4.4.10.1. In theory, this option might support innovative solutions and more flexible energy use like demand-side response (including for Energy Intensive Industries) or storage.

4.4.11. Limitations and Overcoming Limitations

4.4.11.1. Consumer needs (distributional impacts). The Task Force noted the distributional impacts and, whilst it was felt that domestic consumers would not be directly impacted by any move to locational transmission constraints, there were some concerns about increased costs for consumers (via Demand charges) in areas of high constraint especially if the demand in question is not flexible demand.

4.4.11.2. Competition impact. The Task Force discussed the risk arising as some users might not face the cost-reflective charge but some do. Depending on how the charge is allocated, and due the difficulties to allocate the charge cost-reflectively, as highlighted above, will potentially also raise some competition issues.

4.4.11.3. Future-proof (evolution of network utilisation). The Task Force noted the ongoing and fundamental changes to the market including smart meter deployment, the development of flexibility markets, the plan for market-wide settlement reform and Network Options Assessment development plans i.e. costs associated with lesser and no build options filtering through into BSUoS whereas costs associated with a more deterministic build would have otherwise have filtered into TNUoS to resolve the same system issue.

The Task Force view was that rather than trying to incentivise demand turn-up through the structure of the charge an alternative route might be through access to the BM and ancillary services market where there would be better price discovery in a competitive market e.g. in future we could see aggregated EVs competing with generation to alleviate constraints and so reduce the cost of constraints relative to the status quo arrangements.

4.5. Assessment of ‘locational reactive and voltage constraints’

4.5.1. In Deliverable 2 (Section 3) ‘locational reactive and voltage constraints’ was summarised as follows: ‘A locational approach to both reactive and voltage constraints for ESO actions and costs to resolve reactive issues identified in a certain area’.

Summary of ‘locational reactive and voltage constraints’

4.5.2. Whilst there are some theoretical advantages to ‘locational reactive and voltage constraints’ and some of the identified limitations could potentially be overcome, the draft conclusion of the Task Force is that the implementation of this option would not provide a cost-reflective and forward-looking signal that drives efficient market behaviour. The main arguments are as follows:

- A significant issue will arise from the identification the cause of the reactive costs as this is due to a combination of various factors and that voltage is distance-related. Also, voltage constraints would be difficult to identify as they are mobile and quite small relative to total costs.
- The implementation of this potential option might not provide as cost-reflective a signal as it could as the current reactive services costs are based on administrative prices rather than market prices.
- Even if some forward-looking signal could be created, it is expected that the existing limitations discussed in Deliverable 1 will remain and might be exacerbated.

Detailed option evaluation ‘locational reactive and voltage constraints’

C1: Could arrangements provide a signal to parties in a cost-reflective manner?

4.5.3. **Advantages and Uniqueness**

4.5.3.1. The Task Force identified some theoretical advantages if the charge could be allocated on a more locational basis to be more targeted towards market parties causing or exacerbating the reactive and voltage constraint costs. For example, if there is a voltage issue in one zone and costs are incurred resolving that voltage issue due to reactive power absorption payments then those costs will be recovered in the zone contributing to the need for reactive power absorption.

4.5.4. **Limitations and Overcoming Limitations**

4.5.4.1. Administrative price. The ESO currently pays an administrative price for reactive services rather than a market price. Any charge based on these costs is therefore unlikely to be as cost reflective as if it were based on a market price.

Overcoming Limitations. A change to the procurement process and associated costs would be required to facilitate more cost-reflective allocation, rather than having an administrative price. However, the Task Force view is that improvement in procurement process for reactive services seems a more appropriate approach than changing charging arrangements e.g. the ESO pathfinder project related to Reactive Power.

The Task Force also discussed the possibility to have other ways to charge reactive power, for instance with a deviation charge based on power factor i.e. if it goes further away from standard the charge increases by a £/Mvar chargeable value for those parties. However, while this might make the costs more marginal, the cost-reflectivity issues will remain.

4.5.4.2. Complexity of cause of reactive. Similar to locational transmission constraints, the cause of any reactive power costs or voltage constraint costs are due to a combination of factors, including factors not attributable to chargeable parties such as network factors. Each of these factors can exacerbate the need for absorption or generation of reactive power. Also, voltage constraints will be difficult to identify as they are mobile and quite small relative to total costs. Voltage is distance-related and multiple nodes make it much more difficult to ascertain who is on the right and wrong side of the issue and how far away from the issue. Therefore, the Task force questioned if it is possible to identify the polluter for charging purposes.

4.5.4.3. Expanding chargeable parties. Similar to locational transmission constraints, there was discussion in the Task Force on the appropriateness of expanding the charging base to include either interconnectors, or DNOs and TOs, due to the impact such parties can have on the costs associated with reactive power needs. For instance, unavailability of some network elements (e.g. reactors) could lead to additional need to absorb or generate reactive power. However, limitations will arise, regarding requirement for significant legislative and licence change as well as potential for unintended consequences.

C2: Could arrangements provide an effective signal to parties in a forward-looking manner and are they expected to drive useful market behaviour?

4.5.5. **Advantages and Uniqueness**

4.5.5.1. In theory, it could be argued that an effective forward-looking signal could reduce the amount of reactive services needed by the ESO, therefore reducing the costs of managing the system which will ultimately benefits the consumers.

4.5.6. **Limitations and Overcoming Limitations**

4.5.6.1. Difficulty to forecast, complexity, volatility and other market elements taking precedence. The Task Force identified several issued under Deliverable 1 and believes those issues would remain in the case of ‘reactive and voltage constraints’. Therefore, similar to the limitation explained in respect of locational transmission constraints, an expected limitation is that market parties (or ESO) will likely have difficulty forecasting any ‘reactive and voltage constraints’ charge and are unlikely to respond to the signal efficiently.

4.5.6.2. Ability to respond. The signal might be inefficient if you charge a market party that does not have the ability to respond in a beneficial way for the system i.e. through the technical design of the equipment connected to the system or because the local DNO requirements may incentivise users to behave in a certain way.

Overcoming Limitations. The charge could be targeted to those that do not respond (but are able to) and/or those who are causing a problem but cannot change behaviour. However, it is unclear what the impact would be, for instance, on cost-reflectivity, and whether it would be possible to do so.

4.5.6.3. Ex-ante versus ex-post. Similar to locational transmission constraints, an expected limitation is that neither ex-ante nor ex-post charging are likely to result in the creation of an effective forward-looking market signal and so unlikely to influence user behaviour to the benefit of the system and so consumers.

C3: Are the changes practical and proportionate?

4.5.7. **Advantages and Uniqueness**

4.5.7.1. There were no advantages identified in relation to this option above the status quo.

4.5.8. **Limitations and Overcoming Limitations**

4.5.8.1. Static compensation. The Task Force discussed the risk of treating providers of reactive power differently as the compensation for static services are not included in BSUoS and instead are located within TNUoS.

4.5.8.2. Whole system. There was discussion on the Task Force around what is the best way to define the charge and whether whole system thinking, across transmission and distribution would be better for such a charge as distribution networks have a significant impact on reactive power needs. Additional difficulties will arise as Mvar levels differ between transmission and distribution and it will therefore be difficult to have an equivalent value as the impact is different.

Overcoming Limitations. One way to improve this issue would be to target those quite local to the issue to make it effective signal and split by transmission and distribution parties.

4.5.8.3. Link with services providers. There is a need to design the charge to have a feedback loop e.g. to define whether people providing the services should be exempted or not from any locational charge related to such costs.

4.5.8.4. Demand provision. A feasibility issue arises as it is unclear how the contribution of generation and demand will be determined. In particular, for demand the contribution to reactive power will depend on the type of demand.

C4: Any other relevant consideration?

4.5.9. There were no advantages or limitations identified in relation to this option above the status quo.

4.6. Assessment of 'response and reserve bands'

4.6.1. In Deliverable 2 (Section 3) 'response and reserve bands' was summarised as follows: 'An approach where response and reserve costs are divided in different bands to reflect the needs created by different users.'

Summary of 'response and reserve bands'

4.6.2. Whilst there are some theoretical advantages to 'response and reserve bands' and some of the identified limitations could potentially be overcome, the draft conclusion of the Task Force is that the implementation of this option would not provide a cost-reflective and forward-looking signal that drives efficient market behaviour. The main arguments are as follows:

- A fundamental issue that arises again is that the need for response and reserve is not based on the incremental/marginal need (and resulting cost) but on the assessment of the overall network structure and generation mix.
- Even if some forward-looking signal could be created, the impact on existing market arrangements (e.g. the Ancillary Services market or regulatory arrangements) would have to be carefully considered, as contradictory signals might be created.
- The Task Force view is that, even if some signal could be created, it will drive little useful operational behaviour from market parties, as services are procured in advance and parties cannot usefully react to reduce those costs. In addition, any investment signal created in this regard could have wider market impacts with unintended consequences e.g. be likely to simply discourage new large units or those not providing inertia.
- Another major issue would be to allocate the costs adequately as the costs arises from a complex assessment of different scenarios and from a variety of system risks.
- Existing limitations discussed in Deliverable 1 will remain and may be exacerbated.

Detailed option evaluation 'response and reserve bands'

C1: Could arrangements provide a signal to parties in a cost-reflective manner?

4.6.3. **Advantages and Uniqueness**

4.6.3.1. The Task Force identified some potential advantages if the costs of response and reserve could be allocated towards market parties causing or exacerbating the need for those services to be procured. For example, if analysis has shown that an extra 'X' MW worth of response has been procured to continue to protect system frequency due to the largest loss then the costs of this additional response could be paid by those connections in the new range, or by those who are exacerbating the issue.

4.6.4. **Limitations and Overcoming Limitations**

4.6.4.1. Complexity to allocate costs. The ESO defines the needs for response and reserve is based on a complex planning resulting from lots of different scenarios. For instance, response and reserve needs will arise from several very different risks e.g. the loss of a large nuclear power plants or the loss of a large offshore windfarm. Difficulties will arise when defining criteria for the allocation of users and costs to each band. Several issues around cost-reflectivity will arise when building the methodology to allocate the costs e.g. whilst the biggest infeed loss is identifiable different volumes at different times suggests some need for weightings/probabilities to be defined by the ESO.

4.6.4.2. No "incremental" users. The need for response and reserve services is a result of the assessment of the overall network structure and generation mix. It is therefore based on a total approach rather than marginal assessment of incremental users' behaviour in operational or investment timescales (except potentially for new connections). For instance, it would be possible to identify the highest costing contract and the largest loss risk but it will then be complex to identify what is the “greatest cause” incrementally driving those response and reserve needs and costs.

4.6.4.3. Balancing Services contracts. The ESO procures response and reserve availability before real-time aiming to contract the most efficient services. The costs are therefore based on future needs. In particular, the ESO takes into account both availability and utilisation costs when they define what service should be contracted and what the split between availability and utilisation costs are to be contracted. It is unclear how to allocate those costs efficiently to a charge while being cost-reflective and provide a forward-looking signal.

4.6.4.4. Expanding chargeable parties. The Task Force discussed the possibility of extending the banded charge to include other parties affecting largest loss risks and/or inertia risks (e.g. interconnectors and TOs) to be more cost-reflective. For instance, the Western Link is now expected to be an important consideration when the ESO is assessing the response and reserve requirements.

C2: Could arrangements provide an effective signal to parties in a forward-looking manner and are they expected to drive useful market behaviour?

4.6.5. **Advantages and Uniqueness**

4.6.5.1. As response and reserve services are procured in advance, if market parties react to a signal in real-time it wouldn’t change the cost in respect of availability payments. Any signal is unlikely to be in an operational timescale. However, it could be argued that there could be a longer-term signal and that the ESO might in future be able to procure less by factoring expected behavioural change into longer-term procurement actions. The ESO might therefore be able to contract fewer response and reserve services which will ultimately benefit the consumers.

4.6.6. **Limitations and Overcoming Limitations**

4.6.6.1. Unexpected events. The Task Force discussed how market parties are likely to react to this charge and believes that parties would not do things differently, or not be able to do so. Indeed, the need for response and reserve often arises from unexpected events and parties could arguably therefore not take any operational action to avoid the events. If no change of behaviour is expected, the charge will be passed through to consumers (with potential risk premium) in a different manner to the status quo.

4.6.6.2. Protection needs. It was also recognised that the loss of a unit is usually an event that market parties will try to avoid, to avoid costs but also for other reasons. Protection settings are often designed for safety reasons e.g. to protect people working in the power-plant or factory. It was also noted that smaller generators have greater risk of causing cascade in the event of a frequency event at present and which the Loss of Mains Protection setting changes through DC0079 and the work of the ESO with DNOs is seeking to address.

4.6.6.3. Investment signal. The Task Force argues that an investment signal could be created that could have wider implication on the market than reducing costs. While there is potential to construct a signal with banding by loss risk in respect of size, this could incentivise smaller units to be built. Similarly, a signal could incentivise units providing more inertia to be built. The Task Force believes that those signals could have unintended consequences. It was commented that very large units are generally synchronous in nature and so do tend to provide inertia, which is not a rewarded product.

4.6.6.4. Double-counting with imbalance price. The Task Force believes that the signal to avoid unexpected losses and resulting response and reserve costs already exists to an extent through the cash-out process. Some response and reserve costs (e.g. STOR utilisation), as well as scarcity values, are used in the calculation of the imbalance price. This option would therefore lead to a less optimal signal as it could overlap with the current imbalance price signal, causing some degree of double counting.

4.6.6.5. Link with Balancing Market. Most users that can respond to signals in real time can already react in the balancing and ancillary services markets. They could indeed respond to direct ESO calls already with transparent costs through the BM. The Task Force believes that the signal provided by the balancing and ancillary services markets might be more appropriate with regards to response and reserve costs.

4.6.6.6. Link with NOA and connection process. At present NOA takes into account the costs of boundary constraints (i.e. thermal, voltage and stability) to compare against infrastructure costs on a least worst regrets basis. Through the ESO pathfinder projects in future it is expected to take a more holistic view of the balancing and operational costs. In addition, the connection process also (to an extent) considers trade-offs against the deterministic criteria within SQSS. Therefore, arguably many of the expected future costs associated with response and reserve might have been viewed to (on balance) be the economic and efficient costs when compared with infrastructure costs from a network design perspective.

4.6.6.7. Difficulty to forecast, complexity, volatility and other market elements taking precedence. The Task Force identified several issues under Deliverable 1 and believes those issues would remain in the case of 'response and reserve bands'. Therefore, an expected limitation is that market parties (or ESO) will likely have difficulty forecasting any 'response and reserve band' charges and are unlikely to respond to the signal efficiently due to that lack of ability to reasonably forecast.

C3: Are the changes practical and proportionate?

4.6.7. Advantages and Uniqueness

4.6.7.1. There were no advantages identified in relation to this option above the status quo.

4.6.8. Limitations and Overcoming Limitations

4.6.8.1. Maximum versus actual capacity. The bands should be based on actual capacity (or based on operational output) rather than maximum capacity to reflect the impact of market parties on the system. For example, if the largest site is offline for scheduled maintenance, it is not creating a real-time risk and so arguably should not be charged a higher rate for that period of time. This will add complexity to this option especially as the costs incurred might have still included that large plant due to procurement timescales.

4.6.8.2. Timescales. The Task Force discussed the timescales in which the charge should apply, as there is no clear reason for a charge to be calculated in HH periods as under the status quo. However, defining an appropriate charge band period is likely to depend on procurement timescales and/or the availability windows (in respect of improving the cost-reflectivity of charge) and those timescales then vary depending on the products. Complexity arises also due to the evolution of the products in these areas due to European developments and the direction of travel of the ESO i.e. a drive towards closer to real-time procurement.

4.6.8.3. Link with connection and security standards. The Task Force argued that better options to improve the reserve and response costs could be through reviewing current connection and security standards. For instance, SQSS could manage the impact of the largest infeed loss to reduce costs; or, connection conditions in Grid Code could stipulate some requirements to reduce costs.

4.6.8.4. Link with Ancillary Services. Response and reserve costs are driven by arrangements under the ancillary services market. Similarly, to the above argument, the Task Force believes that reviewing the procurement of those services might deliver more benefits to consumers than a charging option.

4.6.8.5. GSR007. Increasing infeed loss risk limits in SQSS through GSR007 (in 2011) would suggest that allowing larger infeed losses was a policy decision where the benefits of larger units outweighed the risks and increased balancing costs.

4.6.8.6. Frequency and inertia are interconnected. A signal to reward inertia as part of a balancing services charge is unlikely to be strong enough to affect investments in different technologies. Assessing the need for a new Balancing Services product to provide inertia is out of scope of the Task Force.

C4: Any other relevant consideration?

4.6.9. **Advantages and Uniqueness**

4.6.9.1. There were no advantages identified in relation to this option above the status quo.

4.6.10. **Limitations and Overcoming Limitations**

4.6.10.1. Risk of gaming. The Task Force discussed the risk of potential gaming around bands, depending on how the bands were structured and how often a chargeable party could change their band so this would require further consideration.

4.6.10.2. Type of users (competition impact). The risk of frequency event might vary by type of user which adds complexity and competition considerations. For example, nuclear sites will generally have more connection redundancy than offshore wind so are less likely to cause a frequency event on the system due to an unplanned outage whilst potentially both being the same size of connection and so potentially included into the same chargeable band.

4.6.10.3. Future-proof (European developments). European developments need to be taken into consideration as several additional requirements regarding response and reserve will be implemented in the following years e.g. separating availability and utilisation, or moving to shorter term procurement timeframes. In particular, European developments foresee the implementation of balancing services platforms (i.e. TERRE and MARI). There is a risk of increased complexity and difficulty to forecast the related charges in the wider European context.

4.7. Assessment of ‘response and reserve utilisation’

4.7.1. In Deliverable 2 (Section 3) ‘response and reserve utilisation’ was summarised as follows: ‘an approach where response and reserve utilisation costs are allocated to the user triggering the need for those services’.

Summary of ‘response and reserve utilisation’

4.7.2. The draft conclusion of the Task Force is that the implementation of this option would not provide a cost-reflective and forward-looking signal that drives efficient market behaviour. Some of the evaluation is similar to the previous option of ‘response and reserve bands’ and main arguments are as follows:

- Similar to other options, as the costs are not based on the impact of an event in isolation (e.g. tripping) but on the situation of the total system at a specific time, there is a fundamental problem that arises to define an optimal cost-reflective signal.
- Even if some forward-looking signal could be created, it will drive little useful operational behaviour from market parties. Indeed, the utilisation of response and reserve often arises from unexpected events and there are already significant incentives not to trip e.g. protection of equipment and safety; parties could likely do little more to avoid tripping if an extra signal not to do so were to be created.
- There is already a signal through existing market arrangements (mainly through the imbalance price). Any additional signal created through BSUoS might therefore be ineffective.
- Existing limitations discussed in Deliverable 1 will remain and may be exacerbated.

Detailed option evaluation ‘response and reserve utilisation’

C1: Could arrangements provide a signal to parties in a cost-reflective manner?

4.7.3. **Advantages and Uniqueness**

4.7.3.1. There were no advantages identified in relation to this option above the status quo.

4.7.4. **Limitations and Overcoming Limitations**

4.7.4.1. Several limitations explained in the previous ‘reserve and response bands’ remain valid in respect of ‘response and reserve utilisation’.

4.7.4.2. Complexity to allocate costs. The ESO utilisation of response and reserve is based on complex system interactions and so it is expected to be a challenge to identify the actual cause of the costs associated with response and reserve utilisation. Issues will arise as the costs of utilisation of response and reserve might be very different for the same issue when it happens at a different time. For instance, a loss of a power plant could lead to sometimes very high utilisation costs of response and reserve and sometimes very low utilisation costs, depending on the status of the overall system at the time of tripping.

C2: Could arrangements provide an effective signal to parties in a forward-looking manner and are they expected to drive useful market behaviour?

4.7.5. **Advantages and Uniqueness**

4.7.5.1. There were no advantages identified in relation to this option above the status quo.

4.7.6. **Limitations and Overcoming Limitations**

4.7.6.1. Several limitations explained in the previous ‘reserve and response bands’ remain valid in relation to ‘response and reserve utilisation’.

4.7.6.2. Unexpected events. The Task Force discussed how market parties are likely to react to this charge and believes that parties would not do things differently, or not be able to do so. Indeed, the need for response and reserve often arises from unexpected events and parties could arguably therefore not take any operational action to avoid the events from happening. There are other significant incentives not to trip e.g. protection of equipment and people safety. If no change of behaviour is expected, the charge will be passed through to consumers (with potential risk premium) in a different manner to the status quo.

4.7.6.3. Response HH costs. As response utilisation varies within HH period questions arise on how to measure the related HH volume and costs due to multiple up and down movements. It is unclear if there is a way to measure response in a way that it can incentivise useful behaviour.

Overcoming Limitations. One way identified to potentially overcome some of the complexity might be to draw a distinction between dynamic and static response, instead of having to constantly follow changes of the frequency. For example, the charge could be charged to certain parties when it goes beyond a given frequency threshold (e.g. 50.2hz). However, it will then not be cost reflective. A frequency utilisation-based multiplier could also be applied so that parties will be incentivised to either not consume or reduce output.

4.7.6.4. Double-counting with imbalance price. The Task Force believes that the signal to avoid unexpected losses and resulting response and reserve costs already exists to an extent through the cash-out process. Some response and reserve costs (e.g. STOR utilisation), as well as scarcity values, are used in the calculation of the imbalance price. This option would therefore lead to a less optimal signal as it could overlap with the current imbalance price signal. This limitation is even more valid for the ‘response and reserve utilisation’ than the ‘response and reserve bands’ as the most utilisation costs are reflected in the imbalance price already. It was noted however that additional FFR costs are not recovered or signalled through imbalance.

Overcoming Limitations. As discussed above, as a principle, imbalance through reserve pricing is supposed to reflect usage and service availability based on value. The Task Force discussed there might be potential in increasing Value of Lost Load (VOLL) as a proxy; or finding a way to link it to BSUoS. At this stage, it is however unclear what the benefits of those approaches would be and this is out of the scope of the Task Force. It is worth noting also that not all those affected by the BSUoS signal will face imbalance price.

4.7.6.5. Difficulty to forecast, complexity, volatility and other market elements taking precedence. The Task Force identified several issued under Deliverable 1 and believes those issues would remain in the case of ‘response and reserve utilisation’.

C3: Are the changes practical and proportionate?

4.7.7. **Advantages and Uniqueness**

4.7.7.1. There were no advantages identified in relation to this option above the status quo.

4.7.8. **Limitations and Overcoming Limitations**

4.7.8.1. Link with Ancillary Services. Response and reserve costs are driven by arrangements under the ancillary services market. The Task Force believes that reviewing the procurement of those services might deliver more benefits to consumers than a charging option.

4.7.8.2. GSR007. Increasing infeed loss risk limits in SQSS through GSR007 (in 2011) would suggest that allowing larger infeed losses was a policy decision where the benefits of larger units outweighed the risks and increased balancing costs.

4.7.8.3. Frequency and inertia are interconnected. A signal to reward inertia as part of a balancing services charge is unlikely to be strong enough to affect investments in different technologies. Assessing the need for a new Balancing Services product to provide inertia is out of scope of the Task Force.

4.7.8.4. Gate closure time. Utilisation costs will not be incurred until after gate closure, and the signal provided through BSUoS could be beforehand. There are generators that have the ability to respond after gate closure, and BSUoS could be an additional incentive for these to respond to this signal. Therefore, we could risk creating a 2-step market as some generators can respond to signals after gate closure time while others don't have this as an option. Another issue is that incentivising more actions after gate closure might not be a useful behaviour for the ESO or efficient market operation.

C4: Any other relevant consideration?

4.7.9. **Advantages and Uniqueness**

4.7.9.1. There were no advantages identified in relation to this option above the status quo.

4.7.10. **Limitations and Overcoming Limitations**

4.7.10.1. Future-proof (European developments). European developments need to be taken into consideration as several additional requirements regarding response and reserve will be implemented in the following years e.g. separating availability and utilisation, or moving to shorter term procurement timeframes. In particular, European developments foresee the implementation of balancing services platforms (i.e. TERRE and MARI). There is a risk of increased complexity and difficulty to forecast the related charges in the wider European context.

4.8. Other considerations

4.8.1. Through the assessment of each of the potential options, the Task Force identified three areas for potential further consideration, which are broader than BSUoS and so were viewed to be out of scope of the Task Force. These are highlighted to indicate where further consideration might be useful in the future and as the Task Force recognises the need to incentivise the market efficiently to drive behaviour that will create value for consumers.

Market splitting

4.8.2. In the assessment of 'locational transmission constraints' (Section 4.4), a fundamental issue that arises with BSUoS is that the charge is based on total costs and not marginal costs. In order to introduce a forward-looking signal for market parties, based on short-run marginal costs, it is recognised that this could be best achieved through market splitting i.e. separating the Great Britain market into different zones with limited cross-zonal capacity for trading. However, the implementation of market splitting should be assessed carefully as other advantages and limitations might arises as well as unintended consequences.

Constraints costs through TNUoS

4.8.3. The Task Force discussed the proposal of removing the constraint costs from BSUoS, and recovering them through TNUoS. The objective of the discussion was to consider the impact of this approach but not whether this would be the best way forward, as further consideration on how to charge BSUoS as a cost-recovery charge needs to take place.

4.8.4. To allow these costs to be recovered through TNUoS would require licence and methodology changes to ensure the revenue is recognised in the right place. In addition, BSUoS is an ex-post product, whereas TNUoS is ex-ante. A mechanism would need to be created to forecast the likely constraint costs, and allow a true-up of these in future years, whilst recognising the impact on the ESO's cashflow.

4.8.5. If we assume that the above can be achieved, then the Task Force highlighted that the only way to create a forward-looking signal with the constraints costs would be to review the locational TNUoS charging methodology. This is because the locational parts of TNUoS are currently calculated using a methodology based on incremental asset cost, which does not consider the ESO costs.

4.8.6. It is unclear however if any change of the locational TNUoS methodology would result in a better outcome for the system and benefits the consumers. In particular, the NOA process aims to optimise network developments, weighting up the capital costs of investment versus constraints costs. RIIO incentives are also in place to ensure the network develops efficiently. Additionally, double-counting would remain an issue if BSUoS is added to TNUoS.

4.8.7. With no change in the current TNUoS methodology, the entire costs of constraints would be recovered through the TNUoS Transmission Demand Residual (TDR). Moreover, the range on generator charges prescribed in European law (€0-€2.50/MWh) means that no more revenue can be recovered from generation than is presently done so. While this will not create a forward-looking signal, some Task Force members highlighted this might be a sensible option to consider when defining the appropriate means to recover BSUoS as a cost-recovery charge.

Cash-out process

4.8.8. In addition to the above, the link between BSUoS and the cash-out process could potentially be further explored to ensure the imbalance price is delivering the best outcome in the context of the elements of BSUoS which are linked with the cash-out process, including Energy Imbalance.

5

Conclusion

5.1. Summary and recommended next steps

5.1.1. The draft conclusion of the Task Force is as follows.

It is not feasible to charge any of the components of BSUoS in a more cost-reflective and forward-looking manner that would effectively influence user behaviour. Therefore, the costs within BSUoS should all be treated on a cost-recovery basis.

Summary of Deliverable 1

5.1.2. Deliverable 1 assesses which, if any, elements of balancing services charges currently provide a forward-looking signal that influences the behaviour of system users.

5.1.3. The Task Force assessed all elements of BSUoS and found that the existing elements of BSUoS do not currently provide any useful forward-looking signal which influences user behaviour to improve the economic and efficient operation of the market.

5.1.4. The Task Force has identified five main reasons why BSUoS is not providing a forward-looking signal: the current BSUoS charges are hard to forecast, complex, increasingly volatile, other market signals are more material and take precedence, and the current BSUoS charges apply to all chargeable users of the National Electricity Transmission System on an equal basis.

5.1.5. The Task Force also discussed the expected current impact of BSUoS on the market and identified two following effect: the addition of risk premium by generators and/or suppliers to mitigate the risk of BSUoS uncertainty and the subtle signal overnight. Neither of these do result in behaviour that are of benefit to the system or ultimately to consumers.

5.1.6. The above assessment and conclusion of the Task Force have been shared with industry through various engagements and a Webinar on 7 March 2019. Stakeholder feedback reinforced the view of the Task Force as the industry broadly agreed with the assessment. The Task Force received feedback that the analysis of the current BSUoS methodology is reasonable and that indeed BSUoS does not currently provide a forward-looking signal.

Summary of Deliverable 2

5.1.7. Deliverable 2 assesses the potential for existing elements of balancing services charges to be charged more cost-reflectively and hence provide better forward-looking signals.

5.1.8. In order to identify potential options, the Task Force assessed whether BSUoS elements have the potential for being charged more cost-reflectively and hence could provide a forward-looking signal. As a result of this assessment, the Task Force identified four such potential options: locational transmission constraints, locational reactive and voltage constraints, response and reserve bands, and response and reserve utilisation. The Task Force discounted some other potential options so those are viewed to be cost-recovery.

5.1.9. Similar to Deliverable 1, the above assessment and conclusion have been shared with industry through various engagements and a Webinar on 7 March 2019. Feedback also indicated overall support for the four potential options identified, and a belief that these options should be further explored.

Summary of Deliverable 3

5.1.10. Deliverable 3 is assesses the feasibility for existing elements of charging any identified potentially cost-reflective elements of balancing services charges on a forward-looking basis to influence user behaviour.

5.1.11. In order to assess the feasibility of the four potential options above, the Task Force used four evaluation criteria relating to the charging being cost-reflective, providing an effective signal, being practical and proportionate as well as any other consideration i.e. reflecting consumer needs, facilitating competition and/or innovation and being future-proof.

5.1.12. After dialogue and debate the Task Force concluded that, whilst there are some theoretical advantages for some of the four potential options identified, the implementation of each of these options would not or could not provide a cost-reflective and forward-looking signal that would drive efficient or effective market behaviour. Indeed, several issues arise from the assessment of each of the potential options that the Task Force felt could not be suitably overcome.

5.1.13. A significant limitation to implement a cost-reflective charge is that BSUoS is based on total costs incurred by the ESO, which can vary significantly. An effectively forward-looking signal should be built from marginal costs rather than total costs, and it is unclear how to achieve this through BSUoS, other than by some form of market splitting i.e. separating the Great Britain market into different zones with limited cross-zonal capacity for trading. Market splitting has not been explored as out of scope of the Task Force. Assuming a forward-looking BSUoS signal could be developed, another significant limitation is that this signal could be ineffective, as other signals are already in place through other market and charging arrangements (e.g. TNUoS, Balancing Mechanism and cash-out) so double-counting issues therefore arise.

5.1.14. In addition, allocating BSUoS costs to market parties responsible for the costs would be highly complex due to various reasons due to services being procured and used by the ESO based on complex assessments of the whole system. Also, there is no evidence that the issues that exist currently (i.e. the charge being hard to forecast, complex, highly volatile, etc) will cease to apply in any of these potential options. Indeed, moving elements of charges to targeted groups of users may have the effect of making their charges more difficult to forecast, complex and volatile.

Conclusion and recommended next steps

5.1.15. Based on the above, the Task Force concluded that, while there is some theoretical potential to develop some options for some elements of BSUoS to be charged differently and in accordance with the aims set out under Deliverable 3, the Task Force assessment identified major limitations that could not be overcome for each of those options.

5.1.16. As the BSUoS charge therefore cannot feasibly provide an effective cost reflective and forward-looking signal which will influence user behaviour to the benefit of consumers, BSUoS should be treated as a cost-recovery charge. Recovery of the balancing services costs, as arising from the total costs incurred by the ESO, should still be recovered even if not intended to provide a forward-looking incentive to market parties.

5.1.17. The Task Force believes that cost-recovery charges should aim to minimise market distorting signals, to benefit the system and ultimately the consumers. As highlighted above in Deliverable 1, the current construction of the BSUoS charge, and the current charging base, may inadvertently send signals to some market parties. These small signals may be leading to additional costs to consumers, and are not beneficial to the system.

5.1.18. The conclusion of the Task Force and above considerations should be considered by Ofgem and the industry in the future design of an effective cost-recovery mechanism for BSUoS. The structure of a BSUoS cost-recovery charge is out of scope of this Task Force.

Consultation question 4:

Do you agree with the overall draft conclusion of the Task Force (Y/N)? Please explain your rationale and provide evidence where possible.

Consultation question 5:

Do you have any other comments in relation to the draft report or draft conclusions of the Task Force?

Appendices

A. Glossary

	Name
APX	Amsterdam Power Exchange
AS	Ancillary Services
BM	Balancing Mechanism
BOA	Bid Offer Acceptance
BSUoS	Balancing Services Use of System i.e. Balancing Services Charges
CM	Capacity Market
CVA	Central Volume Allocation
DCMDG	Distribution Charging Methodologies Development Group
DNO	Distribution Network Operator
DUoS	Distribution Use of System
EIUG	Energy Intensive Users Group
EMR	Electricity Market Reform
ESO	Electricity System Operator
ETYS	Electricity Ten Year Statement
FES	Future Energy Scenarios
FLC	Forward-Looking Charge
GB	Great Britain
LRMC	Long Run Marginal Costs
HH	Half Hourly
MARI	Manually Activated Reserves Initiative
NETS	National Electricity Transmission System
NOA	Network Options Assessment
RCRC	Residual Cashflow Reallocation Cashflow
SCR	Significant Code Review
SP	Settlement Period
SRMC	Short Run Marginal Costs
STOR	Short Term Operating Reserve
SVA	Supplier Volume Allocation
TERRE	Trans-European Replacement Reserve Exchange
TCMF	Transmission Charging Methodology Forum

TCR	Targeted Charging Review
TDR	Transmission Demand Residual
TEC	Transmission Entry Capacity
TF	Task Force
TNUoS	Transmission Network Use of System
TO	Transmission Owner
RoCoF	Rate of Change of Frequency

B. Engagement

B.1. Engagement plan

The Task Force is working collaboratively and transparently. All information regarding the Task Force work is available on the Charging Futures website (i.e. agenda, minutes, presentations, etc).

The table below is an overview of the engagement that the Task Force held when progressing with its programme of work. This is a non-exhaustive list as some additional engagement took place, for instance bilaterally.

Table B1: Overview of engagement held by the Task Force

Date	Channel
15 Jan	Charging Futures Forum presentation on TF work
31 Jan	Email (Charging Futures newsletter) with information from 1st TF and podcast
13 Feb	Transmission Charging Methodology Forum (TCMF) presentation on TF progress and engagement plan
14 Feb	Distribution Charging Methodologies Development Group (DCMDG) presentation on TF progress and engagement plan
7 March	Webinar of TF progresses on D1 and D2
13 March	TCMF presentation on TF progress and engagement plan
26 March	Operational Forum
27 March	Energy Intensive Users Group (EIUG) update on TF progress
11 March	DCMDG update on TF progress
10 April	TCMF update on TF progress
11 April	DCMDG update on TF progress
2 May	Publication of the Draft Report for consultation
7 May	Webinar of TF Draft Report consultation

B.2. Webinar of 7 March on Deliverable 1 and 2

The Webinar objective was to provide an overview of the work of the Task Force in the first six weeks. It gave industry stakeholders a provisional view of Deliverable 1 and Deliverable 2, and provided the opportunity for feedback on Task Force progress, up to that point.

The slides and a recording of the Webinar is available online here. An overview of the content and outcomes of the webinar is as follows.

- The Webinar started with an introduction of the Task Force, explaining the drivers of the Task Force and the wider context, the scope and three deliverables of the Task Force as well as the programme plan of the Task Force.
- A presentation of the draft conclusion on Deliverable 1 at that stage was then shared with the wider industry. The Task Force view is that, in general, the existing elements of balancing services charges do not currently provide a forward-looking signal which influences user behaviour. The exceptions identified being in relation to risk premia and overnight periods of high wind and low demand, neither of which are of benefit to the system or ultimately to consumers

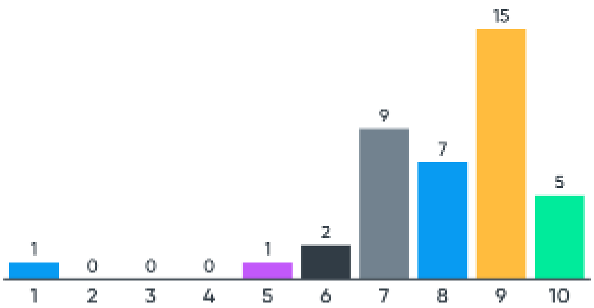
- A presentation of the emerging four potential options under Deliverable 2 to be explored under Deliverable 3.
- At the end a Q and A was held where all questions raised by participants were answered.

Overview of the feedback

At various points of the presentation, we sought feedback from participants and the output of the feedback received is detailed below.

- At the end of the presentation on Deliverable 1, the attendees where asked if they agreed on a scale of 1-10 (10 being fully agree) with the current conclusion of the Task Force for Deliverable 1. The result of the question is available in the figure below.

Figure B1: Result of question on D1 in Webinar 7 March



- The attendees were asked to comment their conclusions and an overview of the comments are as follows.

Table B2: Comments on D1 in Webinar 7 March

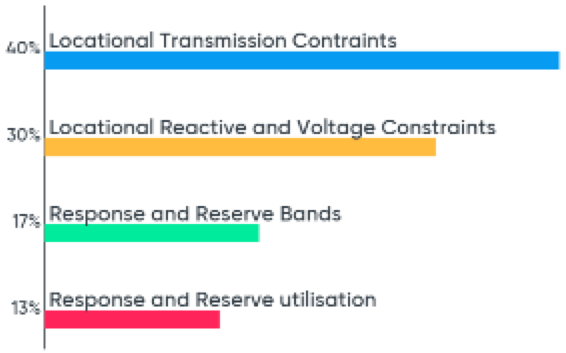
Vote	Number of Respondents	Comments from Respondents
10	5 people	Indeed, the existing elements of balancing services charges do not provide a forward-looking signal (nor - a different issue - is there potential for this) Demand users generally have no ability to vary demand for BSUoS. Your analysis is fair. Agrees with analysis prepared for CMP 250 and CMP 281.
9	15 people	Not clear that BSUoS was ever designed to be a forward-looking charge so would be surprised if it did have a forward-looking aspect. Key driver of constraint cost is network availability. See recent performance of Western Bootstrap. What analysis was done on demand response to signals? Would be good to ensure that this wasn't just anecdotal. Also, as volatility and size of BSUoS increases there may be more incentive for DSR to respond overnight. Because the charge is rolled into one and is not granular or locational. Analysis makes logical sense. Forecasting BSUoS has proven to be difficult in the past. The large number of different components to the charge makes understanding difficult. Market prices much more important factor. Agree that BSUoS sends no sensible forward looking signals to which generators can react. Complexity of BSUoS and difficulty in forecasting does indeed make it very different to influence user behaviour.

8	7 people	Seems that there is no forecastable link. Fix for a year and reconcile?
7	9 people	Beware the impacts on power price longer term. Analysis presented is reasonable. BSUoS has the potential to provide forward looking signals. Largely agree with analysis, though periods of low demand are heavily impacted by reactive and inertia costs, and it would be challenging to produce any forward signal to reduce these costs.
6	2 people	Agree with reasoning so far, but don't want to 100% agree until I can understand how this reasoning will be used / interpreted in later decision making.
5	1 person	
1	1 person	

-

- At the end of the presentation on Deliverable 2, the participants were asked if they believed that the Task Force should focus on the 4 potential options. The result of the question is in the figure below.

Figure B2: Result of question on D1 in Webinar 7 March



- Participants were also asked if they agreed that the Task Force had identified the most suitable Potential Options to further explore and develop in Deliverable 3 and 74% of respondents voted yes.
- Participants were asked to provide a comment in support of their vote and an overview of the comments are as follows.

Table B3: Comments on D2 in Webinar 7 March

Vote	Comment from Respondents
Yes	Who is to blame for a constraint? Demand or generation or both? The elements identified for further assessment are unlikely to be suitable for a FLC, but it may be helpful to investigate to better explain to industry why they are not. Would be good to be clear on definition of "forward-looking" - are we intending a dispatch or investment behavioural signal? Tension/conflict between these and other signals is not necessarily a bad thing - could lead to more efficient system overall. I would also have liked a Maybe option - yes, all sensible but there could be others to consider.

	Is there any consideration as to whether the TO should pick up costs in the Task Force? The main themes have been covered and you are focusing on the principal drivers of volatility in BSUoS that market participants could influence through behavioural change. Other areas have impacts but possibly too complex to progress at this stage. Analysis is logical, and the consideration of ex-ante as a charging methodology makes sense within the frame of forward signalling. I don't understand one of the options so would have preferred to answer "Maybe"! We've had 4 suggestions but there may be plenty of other options not considered. Agree that these are the areas that could be more targeted, although this may increase complexity. The "insurance" costs should surely be stripped out as a fixed charge, not half hourly. Analysis seems reasonable as most discounted costs make sense as cost recovery only purposed, good step to take reactive and voltage more seriously into account. I think you pointed out some sensible options, but this does seem very 'loose' at this stage, with no suggestion about the 'direction' that BSUoS is likely to be going in! Need further explanation on rationale and benefits of options 3 and 4.
No	Locational constraints are a result of under investment in network by economic decision and would need to be addressed alongside TNUOS. Constraint costs which are ‘too high’ is just a signal for reinforcement! Get on it. Response and Reserve Utilisation - loss of double circuit risk more a driver then generation (example, Creyke beck) - very complex and odd to penalise every generator that trips (or major demand changes) - more often it's circuit loss for huge swings. NOA process consider long term constraints then gives a TNUoS signal. Could a SO signal be created as well? This taskforce appears to be just looking at short term signals. For demand users, any reaction to BSUoS must be set by a set forward looking price RoCoF is locational and related to synchronous inertia levels and this does not seem to have been considered. Please consider future needs as well. Not sure if the ESO is already accessing the BM to procure short circuit level but this is locational. The only way to get a forward-looking signal is to have an ex ante price.

- A Q&A was held at the end of the webinar. The table below provides an overview of the questions received.

Table B4: Questions in Webinar 7 March

	Question
1	If constraint costs are considered to be ‘too high’ then surely the logical answer is to manage with storage and reinforce?
2	How do you view the mod that removes BSUoS from generators?
3	Could storage solutions naturally overtime reduce volatility. Should we be looking at encouraging the market to balance the system thus reducing the role of the SO and reduce volatility in BSUoS?
4	Is ESO willing to be transparent in its network management strategy and procurement policy in order to improve predictability of actions and costs?

5	If BSUoS was an open clearing market, participants would be able to see what prices could be.
6	Those elements that can't provide a forward-looking charge (e.g. Black Start) should be separated into a residual charge?
7	How can locational constraints work if NG refuses to publish where locational constraints are due to 'competition reasons'?
8	To give a forward-looking signal you need to publish a forward-looking price. Is this being considered for the constraints or voltage options? Then reconciled?
9	Is it intentional that the Task Force is dominated by generator parties? Not many suppliers?
10	Re answer to make up of Task Force. All suppliers on there also have generation portfolios. No supply only attendees? Bias of Task Force?
11	Where/how/when will the decision be made on what is TNUoS and what is "forward-looking BSUOS"?
12	Following from your earlier comment: if you aren't clear on who's paying, how can you design a signal intended for user behavioural response? Who is the "user"?
13	If BSUoS is spread onto demand, then the taskforce should be dominated by suppliers.
14	How much resource (and cost) does ESO currently devote to BSUoS forecasting and how much would this need to increase to improve quality?
15	Could there be separate charges for demand and supply to avoid penalizing additional demand at times of low load that could reduce costs?
16	Why is Black Start included in the HH charge? Isn't this a fixed charge for the year rather than varying HH to HH?
17	If constraints are the result of underinvestment in the system, shouldn't these be passed to the TO to drive investment?
18	In the future the ESO might use the BM to synchronise plant to procure short circuit level and inertia, is the TF considering this?
19	Can ESO explain why they are so against a cmp250 fixed BSUoS charge approach? Is this an option the Task Force will consider?
20	The only way to get a forward-looking signal is to have an ex ante price.
21	Are the options outlined options for total cost recovery, or could there be a combination of options i.e. a different option for each cost element?
22	Is there merit in looking at how SO costs on the system are created by generation (embedded) in certain parts of the country during the summer de-minis demand? They don't fit neatly into BSUoS?
23	Quite a lot of balancing/system actions are undertaken before real time. Information provision and transparency will allow people to react
24	Do you need to be more transparent between when constraints breach the threshold when transmission investment is needed as some constraints are actually efficient and not a cost

25	Will non-cost reflective or residual elements be recovered from a fixed charge on demand? In line with Ofgem's TCR policy?
26	How could taskforce conclusions interact with CMP308?
27	Would locational constraint charging include a penalty to demand for not off- taking from the system?
28	How will any changes to BSUoS charging be managed alongside the uncertainty of local flexibility markets e.g. Piclo flex?
29	Picking up on the point of the Taskforce Recommendation, what would be the likely timing of the further consideration and a published decision?
30	Demand for not offtaking enough is illogical. The point of the system is to meet demand not to create demand for supply?
31	Are actions related to voltage and RoCof included in your analysis? Wouldn't this be essential forward looking information?
32	Could Energy Imbalance be re-prioritised once the other elements have been considered? Keen the door isn't shut just because it's too difficult
33	Article 16 of EGBL is looking to remove predetermined pricing. This will increase volatility and maybe start creating price signals. Not necessarily a bad thing
34	Is their a linkage into long term SO signals and the NOA process? BSUoS is short term but constraints can be managed by SO solutions (i.e. storage)
35	You need to be considering DSO and make sure signals don't contradict each other.
36	There is a licence condition for generators for Transmission Constraints (not to take advantage) so is competition problems a red herring.
37	If both TNUoS and BSUoS are providing signals, the interactions need to be considered, it wouldn't be efficient for both the send contradicting signals.
38	If level of constraint costs is economically efficient (i.e. don't invest) should the cost be recovered locationally?
39	Are the Task Force factoring in the frontier economics work around vocational BSUoS?
40	Have you analyzed the impact of RoCoF in combination with renewables which is also becoming a driver of BSUoS?
41	Will NGESO be adopting flexibility/SO solutions first?

C. Analysis

C.1 Statistical multivariate analysis of current BSUoS elements (Deliverable 1)

Data used in the analysis

Data spanning a 3-year period, between 1 April 2015 and 25 June 2018, was used in the analysis.

It currently only reflects costs incurred through the BM. The variables used in the analysis are listed below.

Table C1: Data used for analysis

Name	Description
Date	date in YYYYMMDD format
SP	Settlement Period
Day week	Day of week
Constraints	BM Constraint spend
Positive reserve	BM Positive reserve spend
Energy imbalance	BM Energy imbalance spend
Negative reserve	BM Negative reserve spend
Ramping	BM Ramping spend
Other	BM Other spend
Wind	Total (BM and non-BM) wind actual
PV	Non-BM PV units actual
Demand	Demand on the transmission system
IC in	In flow of interconnector
Availability	Sum of TOGA-declared availability at 2 days ahead
Inflexibility	Sum of Nuclear availability

To identify a current signal within the BSUoS charges, a multivariate analysis was used. The objective is to explain the costs of elements of BSUoS, the "dependent variable", by a series of "explanatory variables" (wind, PV, demand, etc).

$$Costs\ of\ (non)\ constraints\ costs = f\ (wind,\ PV,\ demand,\ IC, etc.)$$

The objective of this approach is to try to define if a correlation behind the costs can be identified or if the costs cannot be explained accurately i.e. there are too many drivers and/or none of them seem to be significantly influencing the costs.

The analysis was made for both constraints costs and non-constraints costs. The Task Force focussed on the analysis of constraints costs for Deliverable 1, to explore if these costs provide any useful signals

The figure below explains how to read the results of the tables provided in the further analysis.

Figure C1: Explanation of analysis tables

Costs	Coef	Measure (%)[7]
Wind		
PV		
Demand		
IC		
Etc.		
R-squared		

Explanatory variables

Coefficient of the regression. The sign indicates the relationship, i.e. a positive (negative) number indicates that the costs increase (decrease) when the explanatory variable increases

Statistical measure (Pratt) that indicates which explanatory variable contributes most to explain the cost. i.e. how to "split" R-squared between variables

R-squared is the % of the variance of costs explained by all explanatory variables

Quantitative analysis - Constraint costs

As shown in Table C2, the overall R-squared of the multivariate regression is 38% (i.e. the % of the variance of the constraints costs which is explained by those variables). R-square is a usual statistical tool to explain correlation between a dependent variable (constraints costs) and explanatory variables (wind, PV, demand, etc). The result means that all identified explanatory variables used in this analysis can explain 38% (of the 100%) of the variance of the constraints costs.

In Table C2, we also use a statistical measure to identify if some explanatory variables are more "significant" (i.e. explain a bigger part of the R-squared) than other variables. It can be seen in the table that 2 variables - wind (20%) and demand (18%) - contribute the most to the aggregated R-square for constraint costs. Other explanatory variables do not seem to be significantly explaining the variance of constraints costs. The importance of wind and demand are each relatively low but similar when explaining the constraint costs (respectively 20% and 18%).

Table C2: multivariate analysis for constraints costs

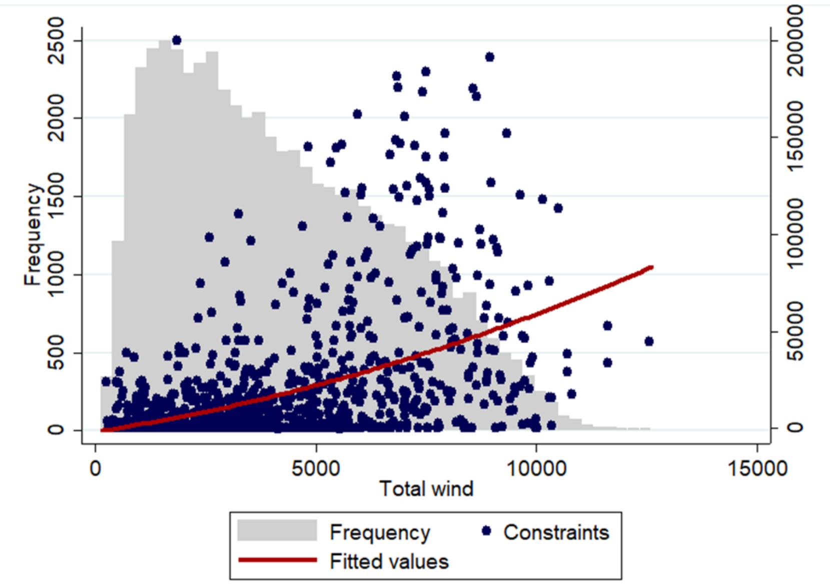
Constraints costs	Coef	Measure
Wind	2.197	20.42
Wind (square)*	0.000393	
Demand	-10.85	17.81
Demand (square)*	0.000122	
PV	-1.826	1.330
IC import	-3.869	1.326
Availability	-0.179	0.000805
Inflexibility (Nuke)	0.790	0.128

[7] Pratt, J. W. (1987). Dividing the indivisible: Using simple symmetry to partition variance explained. In *Proceedings of the second international Tampere conference in statistics, 1987* (pp. 245-260). Department of Mathematical Sciences, University of Tampere

Time trend	0.619	1.983
SP	592.9	-4.131
Day of week	6431.2	-0.449
Month	-3039.7	0.499
Year	-13284.8	-1.184
R-squared	**37,7%**	

Of the drivers investigated, wind is one of the few which cannot be immediately discounted as insignificant in explaining constraints costs (20%), and so the shape of the relationship is analysed in more detail below. In Figure C2, it can be observed that the shape of the relationship between constraint costs and wind is mainly linear and positive, i.e. constraints costs do broadly increase when the wind increases, although there is pronounced scatter.

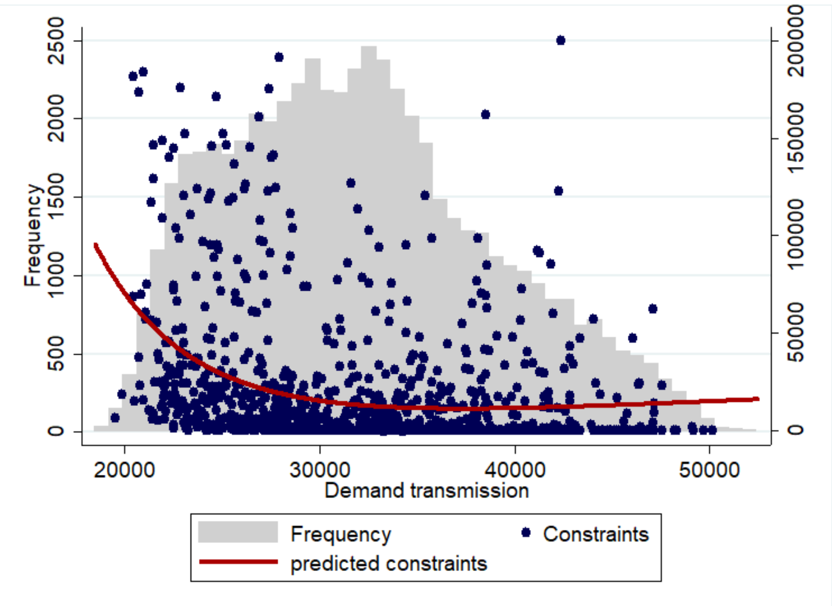
Figure C2: shape of the relationship between constraints costs and wind



Source: Data of constraints costs spend (BM only) and actual wind output (BM and non-BM), years of data between 1 April 2015 and 25 June 2018.
Note: In order to make the figure clear, only 1000 constraints costs observations were randomly selected. However, the frequency and fitted values line is based on all observations.

Similarly, as demand is another not-insignificant driver behind constraints costs (18%), the shape of the relationship is analysed in more detail. In Figure C3, it can be observed that the shape of the relationship between constraint costs and demand is mainly squared (U-shape). We observe an important increase of constraint costs when demand is low and a slight trend for costs to increase when demand is higher; more extreme demand drives costs.

Figure C3: shape of the relationship between constraints costs and demand

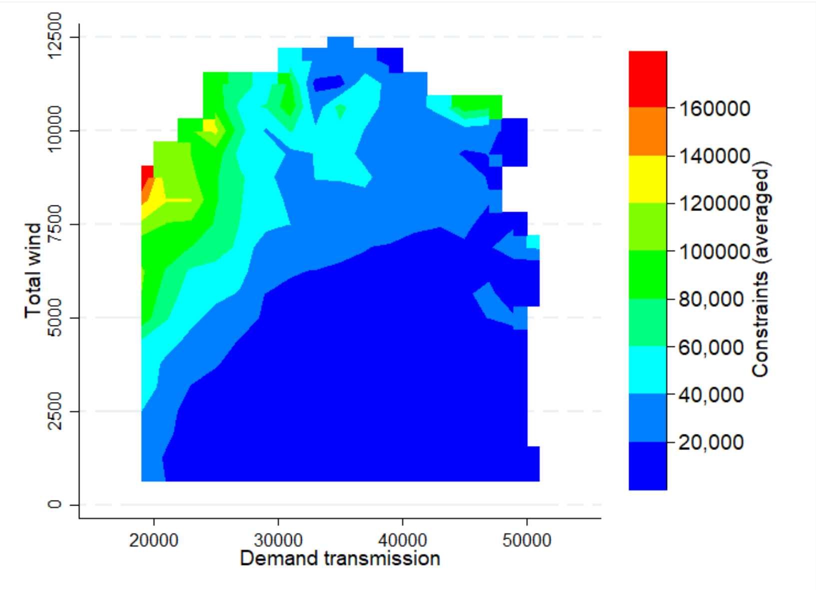


Source: Data of constraints costs spend (BM only), actual wind output (BM and non-BM) and demand (transmission system only), data between 1 April 2015 and 25 June 2018.

Note: In order to make the figure clear, only 1000 constraints costs observations were randomly selected. However, the frequency and fitted values line is based on all observations.

We also looked at the impact of both wind and demand on constraints costs. It is observed that there is an important reinforcing effect between the two variables, wind and demand. Figure C2, shows that when the wind is high, the range of constraints costs is broad (i.e. some constraints costs are still very low even when wind output is high). Similarly, from Figure C3, when demand is low, the range of constraints costs is broad (i.e. some constraints costs are still very low when demand is low). Figure C4 below shows that the constraints costs are expected to be high mainly when both elements are combined, when both wind is high and demand is low at the same time.

Figure C4: constraints costs value for wind and demand



Source: Data of constraints costs spend (BM only), wind actual demand (transmission system only), data between 1 April 2015 and 25 June 2018.

The observations above can be explained by various reasons, including:

- High wind can drive constraint costs, due to a large volume of wind generation (as well as other generation) not always being located close to consumption and being behind derogated boundaries – that is, located in areas where physical network reinforcement may be deferred either temporarily or permanently to achieve overall least-cost system operation.
- "Connect and Manage" has enabled connections to be made where the network is not fully reinforced leading to constraint costs in these zones.
- When demand is low balancing services costs might be higher due to additional actions from the ESO to ensure margins and response is available on the system.

Finally, it is worth noting that even if constraint costs can be partially explained by wind and demand, this is only true to a limited extent (in statistics, a R-squared of 38% is still relatively weak); the reasons for balancing services costs not providing a signal in general remain valid.

Quantitative analysis - Non-constraint costs

A similar multivariate analysis was produced for all non-constraints costs. The analysis was done for the total of non-constraints costs, even though the Task Force understands that it is possible that some costs elements might have trends that counterbalance each other. However, parties are exposed to the signal provided by the aggregation of all balancing services charges.

Table C3 illustrates that when assessing each element of the balancing services costs the evidence is that there is little forward-looking signal in the non-constraints costs. Indeed, the overall R-squared of this multivariate analysis is only 10% (i.e. the % of the variance of all non-constraint costs explained by the variables). Although weak, Demand and PV appear to be the primary explanatory variables.

Table C3: multivariate analysis for non-constraints costs

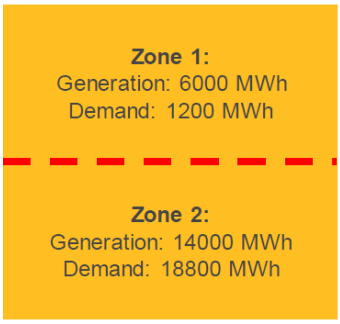
Non-constraints costs	Coef	Measure (%)
Wind	0.939	0.173
Demand	1.697	3.031
PV	-5.913	5.255
IC import	-1.042	0.170
Availability	-0.783	-0.105
Inflexibility (Nuke)	3.582	0.402
Time trend	-0.829	0.485
SP	1252.4	0.0323
Day of week	-6039.7	0.153
Month	846.2	1.428
Year	17633.4	-1.082
R-squared	**9.9%**	

C.2 Two-zone model development for the assessment of 'locational transmission constraints' (Deliverable 3)

In support of the Task Force discussion on locational transmission constraints a simplified two-zone model was created. It highlights some of the options for charging transmission constraint costs on a more locational basis, alongside how balancing charges on a £/MWh basis could change.

The two-zone model is illustrated in the figure below. It is indicative of the current Great Britain market with data drawn and smoothed from indicative actual data, i.e. Settlement Period 34 on 6th January 2019. The total volume is, assumed for illustration, to be 40,000MWh.

Figure C5: two-zones model illustration - volume



It is worth noting that the constraint costs are a function of the cost of bidding generation off (or increasing demand) behind an active constraint multiplied by the volume and the cost of offering generation on (or reducing demand) in front of an active constraint multiplied by the volume. The charge is then a function of the constraint costs and the chargeable volume. The total cost is, assumed for illustration, to be £125,000 of which £25,000 are attributed to constraints.

Under the status quo arrangements the costs would be socialised over the total volume in the Settlement Period: £125,000 / 40,000MWh = £3.125MWh. The charge will apply to all parties equally, so generation and demand in zone 1 and 2 will be charged £3.125MWh.

Who will pay the charge?

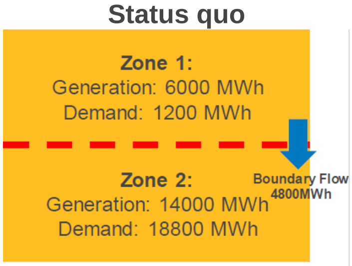
In the future, different sub-options for charging on this basis could apply, depending on who would be charged (or credited) the constraints costs. The Task Force investigated the following potential sub-options:

- Targeting costs to Z1 Generation
- Targeting costs to Z1 Generation and Z2 Demand
- Targeting costs at Z1 Generation and Z2 Demand, and crediting the same tariff to Z2 Generation and Z1 Demand
- Targeting costs at Z2 Demand
- Targeting costs of Z2 Demand, and crediting the same tariff to Z1 Demand

The figure below describes the tariff structure for each potential sub-option compared to the status quo. At this stage, no reaction by market parties to the resulting signal was assumed.

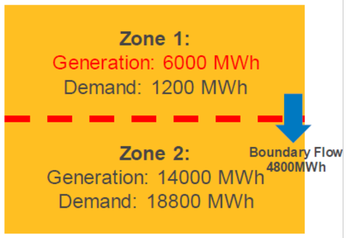
Figure C6: two-zone model – sub-options and tariffs comparison

Status quo



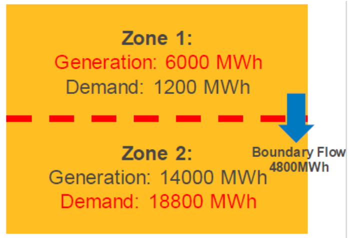
	Tariff
Z1 Gen	3.125
Z1 Dem	3.125
Z2 Gen	3.125
Z2 Dem	3.125

Z1G



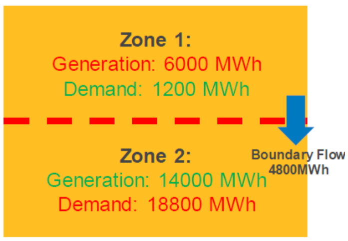
	Tariff
Z1 Gen	**6.67**
Z1 Dem	2.50
Z2 Gen	2.50
Z2 Dem	2.50

Z1G & Z2D



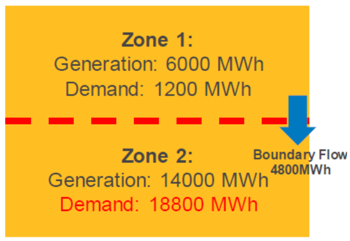
	Tariff
Z1 Gen	**3.51**
Z1 Dem	2.50
Z2 Gen	2.50
Z2 Dem	**3.51**

Z1G/Z2D & Z2G/Z1D



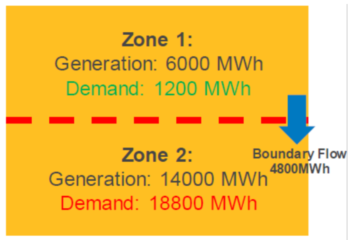
	Tariff
Z1 Gen	3.89
Z1 Dem	1.86
Z2 Gen	1.86
Z2 Dem	3.89

Z2D



	Tariff
Z1 Gen	2.50
Z1 Dem	2.50
Z2 Gen	2.50
Z2 Dem	3.82

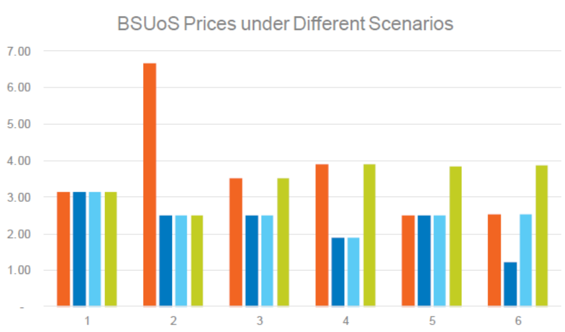
Z2D & Z1D



	Tariff
Z1 Gen	2.54
Z1 Dem	1.21
Z2 Gen	2.54
Z2 Dem	3.87

In addition to the above, the figure below provides an overview of each of these different tariffs.

Figure C7: two-zone model – tariffs overview



1. Status Quo
2. Target Z1 Gen
3. Target Z1 G and Z2 D
4. Target costs of Z1G/Z2D, and credit same tariff to Z2G/Z1D
5. Target Z2 Demand
6. Target Z2 Dem and credit same tariff to Z1D

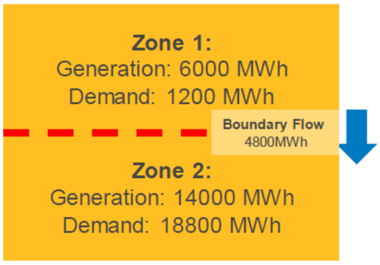
Impact on user behaviour

Through some assumptions about user behaviour, the below shows the effects user behaviour could have on the costs and benefits associated with altered user behaviour to the benefit of the system and consumer. As can be seen from each of the illustrative examples below, whilst in some of the models there is some potential for some of the parties to benefit, the expected benefit would be at such a level that other market signals would continue to take precedence. For example, under illustrative scenario 2 (target additional costs to Z1 Generation) we might not expect a generator to reduce generation for that Settlement Period for a benefit of £1.39MWh.

Figure C8: two-zone model – illustrative effect of users' behaviour

Status quo

There is no signal for any particular zone to behave.
The effect is assumed zero response to the cost of constraints.



	Original Tariff	Tariff after market response
Z1 Gen	3.125	3.125
Z1 Dem	3.125	3.125
Z2 Gen	3.125	3.125
Z2 Dem	3.125	3.125

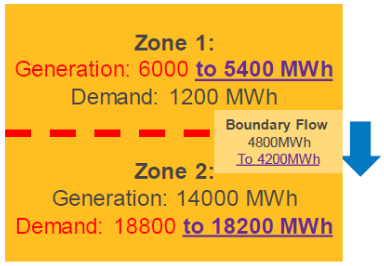
Z1G

The higher tariffs for Z1 Generators, causes a drop in Z1 generation and an increase in Z2 generation to keep the system balanced. Assumed that (10%) 600 MWh of generation moves from Z1 (now 5400MWh) to Z2 (now 14,600 MWh) and this reduced constraints costs from £25k to £15k, as border flows reduces.
Effect is to reduce Z1 Gen Tariffs from £6.67/MWh to £5.28/MWh

	Original Tariff	Tariff after market response
Z1 Gen	6.67	5.28
Z1 Dem	2.50	2.50
Z2 Gen	2.50	2.50
Z2 Dem	2.50	2.50

Z1G & Z2D

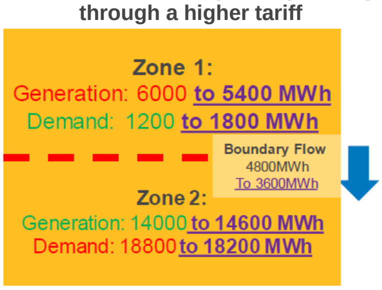
The higher tariffs for Z1 Generators and Z2 Demand, causes a drop in Z1 generation and Z2 demand. Assumed that (10%) 600 MWh of Generation reduction, is met by reducing Z2 demand to 18200MWh and this reduces constraints costs from £25k to £15k, as border flows reduces.
Effect is Z1G and Z2D Tariff reduce from £3.51/MWh to £3.19/MWh, but other tariffs increased by 6p/MWh as lower overall volumes



	Original Tariff	Tariff after market response
Z1 Gen	3.51	3.19
Z1 Dem	2.50	2.56
Z2 Gen	2.50	2.56
Z2 Dem	3.51	3.19

Z1G/Z2D & Z2G/Z1D

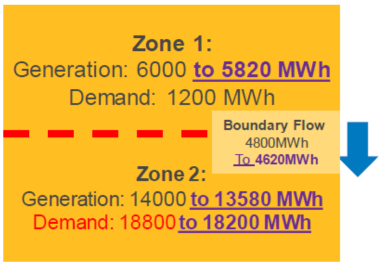
The higher tariffs for Z1 Generators and Z2 Demand causes a decrease in both. The lower tariff in Z1 Demand and Z2 Generation causes an increase in both. Assumed all changed are 600MWh, but that constraint is now £10k as effect over the boundary is double compared to previous options.
Effect is Z1 Gen / Z2 Demand tariffs reduce, but (as it is the same tariff credited) Z1 Dem and Z2 Gen are "penalised" for doing the right thing through a higher tariff



	Original Tariff	Tariff after market response
Z1 Gen	3.89	3.10
Z1 Dem	1.86	2.25
Z2 Gen	1.86	2.25
Z2 Dem	3.89	3.10

Z2D

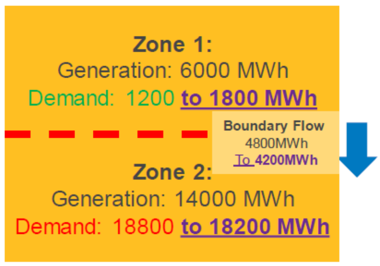
The higher tariffs for Z2 Demand causes a 600MWh reduction, met by reduction in Z1 (to 5820) and Z2 generation (to 13580) in proportion to original. However, this means only slightly reduced flow over the border, as no signal to affect generation in the right zone. Assumed constraints costs only reduces to £20k.
Effect is Z2D tariffs decreases, but constraints not fully removed as no way to target where generation reduction comes from.



	Original Tariff	Tariff after market response
Z1 Gen	2.50	2.58
Z1 Dem	2.50	2.58
Z2 Gen	2.50	2.58
Z2 Dem	3.82	3.68

Z2D & Z1D

The higher tariffs for Z2 Demand, causes a 600MWh reduction, but the lower tariff in Z1 Demand sees an increase of 600MWh Assumed that the reduced constraints costs moves from £25k to £10k as border flow lower
Effect is Z2D tariffs reduces from £3.87/MWh to £3.36/MWh, but Z1 Demand tariffs increases by 50p/MWh for "doing the right thing".



	Original Tariff	Tariff after market response
Z1 Gen	2.54	2.54
Z1 Dem	1.21	1.71
Z2 Gen	2.54	2.54
Z2 Dem	3.87	3.36

Figure C9: two-zone model – overview of illustrative effect of users' behaviour

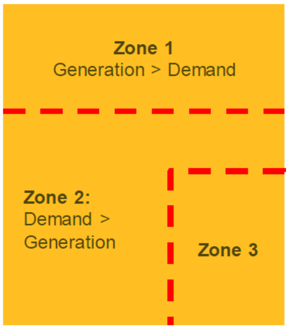
Change £/MWh in Zonal Tariffs	1. Status Quo	2.Target Z1 Gen	3.Target Z1 Gen and Z2 Dem	4.Target Z1G/Z2D, credit Z1D/ZG	5.Target Z2 Demand	6.Target Z2D, CreditZ1D
Z1 Gen	-	-1.39	-0.30	-0.79	0.08	-
Z1 Dem	-	-	0.08	0.38	0.08	0.50
Z2 Gen	-	-	0.08	0.38	0.08	-
Z2 Dem	-	-	-0.30	-0.79	-0.15	-0.51
Change in Volume MWh						
Z1 Gen	0	-600	-600	-600	-180	-
Z1 Dem	0	-	-	+600	-	+600
Z2 Gen	0	+600	-	+600	-420	-
Z2 Dem	0	-	-600	-600	-600	-600
Change in Border Flow	0	-600	-600	-1200	-180	-600
Assumed (reduce) constraint	£25k	£15k	£15k	£10k	£20k	£15k

However, there is a possibility that some market parties could react to a signal at some specific moments. For instance, some demand side response could react to the signal (e.g. as a new revenue opportunity) in some specific cases when benefits are very high. Although there is an argument this should be via the BM.

Multi-zone complexity

There was discussion in the Task Force about the vastly greater complexities of the actual system. In reality, there are currently dozens of potentially interlinked and constrained boundaries on the National Electricity Transmission System.

Figure C10: multi-zone model illustration - volume



A handful of initial Task Force observations from the above model include: whether market parties can reasonably be expected to know changes to cost and volume, how they then interact with the charge, whether the polluter pays model is viable and whether it is possible to provide an economically efficient signal or whether it simply provides a more targeted cost recovery. These points and others are further explored in the evaluation in Section 4.

D. BSUoS and wider context

This Section provides a brief overview of recent, ongoing and future developments which provide further context in relation to BSUoS and the work of the Task Force. In considering changes to BSUoS the Task Force has consider each of the areas outlined below.

Wider charging context

The way in which the ESO operates the National Electricity Transmission System (NETS) is evolving, and will continue to do so as we transition to a smarter and more flexible energy system. For instance, operating the transmission system will be affected by increased renewable energy sources, decentralisation of generation and change in demand patterns, including the impact of EVs.

These changes aim to deliver greater consumer benefits and will require a review of current commercial, regulatory and technical arrangements. This might be achieved through a review of the charging arrangements.

The Balancing Services Charges Task Force recognises the need to be mindful of the wider charging context when considering the impact of their recommendation on the future direction of BSUoS.

TNUoS charges

Transmission Network Use of System (TNUoS) charges recover the cost of installing and maintaining the national electricity transmission system in GB (more information can be found here). TNUoS tariffs allow the ESO to recover the capital costs of building and maintaining the transmission network on behalf of the Transmission Owners (TOs).

The ESO sets TNUoS tariffs for connected generators and suppliers. Generators are charged according to their Transmission Entry Capacity (TEC) and suppliers are charged based of their consumers' demand. All tariffs are based on which geographical zone users are connected to (or using) the network and have both locational and residual elements.

These tariffs reflect the relative transmission cost of connecting at different locations (under the current methodology there are 27 generation zones and 14 demand zones) and recover the total allowed revenues of the onshore and offshore TOs. Where the total amount recovered through TNUoS either exceeds or falls short of the TO's total allowed revenues, adjustments are made in later charging years.

TNUoS for generators is made up of two components: the wider tariff, set to recover the costs incurred by a generator for the use of the main interconnected transmission system, and the local tariffs, for the use of assets required to connected to the main interconnected transmission system. A proportion of the wider tariff for conventional non-intermittent generators and peaking generators is the peak element which reflects the cost of using the system at peak times.

The average generation tariffs must also remain below the cap of €2.50/MWh set by European Commission Regulation (EU) 838/2010. To ensure that the TOs' total allowed revenues are recovered but also that the European Commission Regulation is adhered to, there is a 'residual' charge added to all generator tariffs once the wider and local charges are determined. Note that this charge can be negative.

To reflect the cost of connecting in different parts of the network, the ESO determines a locational component of TNUoS tariffs using two models of power flows on the transmission system: peak and year-round. Where a change in demand or generation increases power flows to the point where the system needs to be developed, tariffs increase to reflect the need to invest. Similarly, if a change reduces flows on the network, tariffs are reduced to reflect the relative cost of reducing flows at one point on the network.

Demand is charged differently depending on how consumption is settled, and across each of the 14 demand zones there is a locational element and a residual element. Half hourly gross demand tariffs are charged to customers on their metered output during the triads reflecting the relative cost of using the system at peak times. Triads are the three half hour settlement periods of highest net system demand between November and February inclusive each year and separated by at least ten clear days. Non-half-hourly charges are levied based on annual consumption between 16:00 and

19:00 as a pence/kWh charge. Exports from embedded generation are credited the Embedded Export Tariff, for exports over the Triad periods.

DUoS charges

Distribution Use of System (DUoS) charges recover the costs that Distribution Network Operators (DNOs) face for installing, operating and maintaining the local distribution networks.

The charge is based on the Maximum Import Capacity and Maximum Export Capacity of a connection and the volumes of electricity flowing to and from the connection in relation to other users on that network or region. The specific composition of DUOS charge depends on the size and type of connection. Rates vary depending on region, as well as the time of day.

Network development context

Network planning and system operation are strongly interlinked, and there is a constant tension between facilitating network investment (the cost of delivering long term capability and reliability) and short term service performance (secure and cost effective system operation in real time). Both sets of costs are recovered through TNUoS (for network investments) and BSUoS (for system operation), and are ultimately paid for by consumers.

Network Options Assessment (NOA)

TOs and the ESO are licence obligated to develop an efficient, coordinated, and economic system of electricity transmission. This is partly facilitated through ESO's publication of the Network Options Assessment (NOA) which provides important information to TOs to support decisions on transmission developments (more information can be found here).

The NOA process foresees that the ESO and the TOs work together to assess a wide range of options that could meet the future system requirements. The power flow requirements are determined by the Electricity Ten Year Statement (ETYS) based on data from the Future Energy Scenarios (FES). The ESO may propose alternative options for TO consideration and submit potential operational or commercial options at this stage of the process.

The 'optimisation' process of the NOA then involves the ESO performing an economic assessment on each of the possible options, weighing up the capital cost to implement them versus the constraint cost saving over time. A constraint cost is the monetary value incurred in limiting the bulk power flow over a given boundary. Constraint costs represent part of the BSUoS charges, whereas capital costs influence TNUoS charges.

The TOs will take consideration of the NOA recommendations together with other factors which are beyond the ESO's economical assessment, such as deliverability and safe and secure operation of the transmission network. Investment decisions on these identified reinforcement works will be made in accordance with TO's license obligations and pass through into TNUoS charge to the transmission network users.

Connect and Manage

In 2010, the Government decided to implement a 'Connect and Manage' regime for grid access on the transmission network. This regime enables new generators to connect to the network ahead of wider transmission system reinforcement being finalised, recognising potential consequences on constraints costs.

The system charging methodology should be compatible with the requirements of the connect and manage regime for new connections. Under condition C26.6 of the Transmission Licence, it is stated that the 'use of system charges resulting from transmission constraints costs are treated by the licensee such that the effect of their recovery is shared on an equal per MWh basis by all parties liable for use of system charges'.

Other Task Forces and Workgroups

Other charges to use the network are also currently under review and the changes will likely impact all network users. The Charging Futures programme is coordinating changes across all charges (i.e. TNUoS, DUoS and BSUoS). It aims to give all industry stakeholders the opportunity to take part in shaping the changes (more information here).

Reviews of network charges may change the methodologies used to determine how much a user pays, as well as which users pay certain charges. Since this will have a consequential impact on the costs charged to all user types, Charging Futures will work to help users understand the changes made.

The Balancing Services Charges Task Force recognises the need to be mindful of these ongoing reviews of charging arrangements to ensure the BSUoS recommendations take account of the wider context and avoid duplication of work.

Targeted Charging Review (TCR)

In August 2017, Ofgem launched a Significant Code Review (SCR) to drive forward the Targeted Charging Review. The SCR was launched to address their concern that the current framework for residual and cost-recovery charging may result in inefficient use of the networks and unfair outcomes for consumers.

The TCR is looking at how electricity network residual charges should be set in future, for both transmission and distribution. The principles Ofgem have used to assess potential changes are: reducing distortions, fairness, proportionality and practical considerations.

Ofgem published their minded to decision and draft impact assessment in November 2018. Ofgem believe (subject to consultation) that residual charges should be recovered from suppliers, rather than generators or a combination of suppliers and generators, and should be recovered as either a fixed charge or a capacity based charge.

A consultation took place and closed in February 2019 on the TCR, which enables industry to give their views on Ofgem's position. The minded to decision and draft impact assessment might still be subject to change before Ofgem release their full decision in Summer 2019.

The outputs from the Balancing Services Charges Task Force will be considered by Ofgem alongside the TCR consultation feedback prior to their decision and policy statement on the TCR.

Access and Forward Looking Charges SCR

On 18 December 2018 Ofgem launched their Electricity Network Access Project SCR. The review aims to (i) ensure that electricity networks are used efficiently and flexibly; (ii) ensure they reflect users' needs, allowing consumers to benefit from new technologies and services; and (iii) do this while avoiding unnecessary costs on energy bills.

The SCR scope includes: (i) a review of the definition and choice of access rights for transmission and distribution users; (ii) a wide-ranging review of DUoS charges; (iii) a review of the distribution connection charging boundary; and (iv) a focused review of TNUoS charges.

Under Charging Futures, two Task Forces were previously established to assist in the policy development process: The Access Task Force and Forward-Looking Charges Task Force. The objective of these Task Forces was to consider what changes could be taken forward, in each policy area, in order to drive benefit to users through supporting more efficient use and development of network capacity. The work of these two Task Forces fed into the SCR but could also be useful to consider for the Balancing Services Charges Task Force.

Therefore, the Balancing Services Charges Task Force also needs to be mindful of the Electricity Network Access Project SCR which plans to publish working papers and other discussion materials in Summer 2019.

CMP250 – Stabilising BSUoS over a 12-month period

CMP250 was raised by Drax on 28 August 2015 (more information can be found here). The proposal aimed to fix BSUoS for a 12-month period with a known value 12 months ahead. Under or over-recovery would then be recovered or returned in the following charging period.

The proposer argued that increasing volatility makes BSUoS harder to forecast and that volatility is too high to be predictable, which, they believed, affected competition in the market. They also argued that BSUoS is a cost recovery mechanism and does not provide a meaningful market signal. They believed their proposal would reduce risk premia on BSUoS forecasts.

The majority of the Workgroup and consultation respondents agreed that BSUoS volatility was increasing. The Workgroup found little or no pattern in overall monthly BSUoS costs. Falling transmission system demand was recognised as a key factor in the determination of BSUoS, noting interactions with future system changes (i.e. solar and transmission investment). Increasing constraint costs and reducing inertia were also noted as key cost drivers. A strong relationship with wind volumes was not established.

Respondents had mixed views on the effects of the modification on competition in the generation of electricity. Some members however believed there is an effective signal, and that dispatch decisions would be affected by moving BSUoS to ex-ante pricing.

The Workgroup discussed BSUoS as a market signal or a cost recovery mechanism. The majority of the Workgroup considered BSUoS as cost-recovery, not a market signal.

The view of the Workgroup was that targeting BSUoS to half hours was partially achieved as, for instance, constraint costs are smeared across market participants. Only some elements of BSUoS (e.g. BOAs, trading costs, STOR availability) are allocated to specific half hours. All other costs are computed daily and allocated to settlement periods through volume weighting.

The Workgroup noted fixing elements of BSUoS makes them inherently less cost reflective.

Ofgem decided to reject CMP250 on 25 October 2018.

- Objective A (competition) – Ofgem noted there wasn't enough evidence to judge if the transfer or risk resulted in overall savings or improved competition. In particular, there was a lack of evidence related to the value of the notional reduction in risk premia used by both suppliers and generators.
- Objective B (cost reflectivity) – Ofgem stated there was little analysis on the components of BSUoS and their effect on volatility. It noted any future assessment of BSUoS would "*benefit from investigating the components that make up BSUoS in order to determine which are best suited to cost recovery and which are more suited to a cost reflectivity approach*".
- *Ob*jective C (licencee's business) – Ofgem considered the change to not be reflective of changes within the transmission licencee's business.
- Objective E (efficiency of the methodology) – Ofgem's view was CMP250 would require change to licences and would be at odds with the outcome of other reforms e.g. the TCR.

CMP281 – Removal of BSUoS from storage facilities

CMP281 was originally raised by Scottish Power on 22 June 2017 (more information can be found here). This modification aims to remove the liability of off-taking BSUoS charges from storage facilities operated under a generation licence.

The proposer argued that storage paid for BSUoS on import and export and therefore was paying twice compared with other generation, creating a market distortion.

The Workgroup raised concerns about the differential treatment of Supplier Volume Allocation (SVA) and Central Volume Allocation (CVA), including the netting of embedded benefits. They believe it may require appropriate changes to Residual Cashflow Reallocation Cashflow (RCRC) and C26 of the transmission licence (socialisation of constraint costs).

In their open letter on storage and charging reform, Ofgem stated that CMP281 "would appear to broadly align with our stated principles, insofar as BSUoS is a cost recovery charge. But we expect the workgroup to monitor the outcomes of the BSUoS Task Force closely". It is expected that the work on CMP281 will not be concluded before the Task Force completes its programme of work.

CMP308 – Removal of BSUoS from Generation

CMP308 was raised by EDF Energy on 12th October 2018 (more information can be found here). This modification seeks to remove the liability to pay BSUoS charges from generation, and is similar to CMP201 which Ofgem rejected in 2014 – the proposer argues that there have been developments which require further assessment, including significant growth in GB electricity interconnector capacity since 2014, and to come. Interconnectors have been exempt from paying BSUoS since 2012 due to European regulations, and continental European generators generally do not pay BSUoS-like charges; the proposer of CMP308 therefore alleges a competitive disadvantage to GB generators, which do pay such charges.

Ofgem was previously concerned about short-term price increases due to higher GB generation. BSUoS was removed from interconnectors due to European regulations. As interconnector volume is increasing, the proposer expects that the generation versus demand split is to be 47% versus 53% by 2020.

The proposer view is that this will align GB arrangements with other EU states, allowing more effective competition with EU generators. The proposer expects this change to be neutral, over the long-term, regarding consumer impacts as the increase in BSUoS charge is offset by the change in generation BSUoS in the wholesale price. They believe the change needs an effective lead time after the decision, before implementation, of 2 years for the market to adjust so that the modification doesn't have adverse short term effects.

The Workgroup is exploring how the implementation timeframe may need to be aligned with longer-term contracts and how BSUoS is incorporated into different traded products. Another concern is how will the risk premia change in relation to signals from the balancing mechanism (i.e. TERRE). They also raised the fact that overnight BSUoS is higher than other periods.

It is expected that the CMP308 paper will be complete in a similar timeframe to the Task Force, targeting an Ofgem decision at the end of the first half of 2019. However, the two pieces of work are distinct: The Task Force is looking at elements of BSUoS and whether there can be a forward-looking signal, whereas the CMP308 addresses the perceived defect of uncompetitive charging between GB and EU generators.

Wider Market context

Wholesale market and capacity market

Supply and demand for electricity must be matched, or balanced, at all times. In GB, this is primarily done by suppliers, generators, traders and customers trading in the competitive wholesale electricity market.

The Capacity Market (CM) was introduced by the UK government through its Electricity Market Reform (EMR) package, as the previous energy-only market raised security of supply concerns. The objective of the CM is to ensure security of electricity supply by providing a payment for reliable sources of capacity and encourage investment to replace older power stations, and to provide backup for more intermittent and inflexible low-carbon generation sources.

Balancing Mechanism (BM) and Ancillary Services (AS)

One of the ESO's core roles is residual electricity system balancer for GB. This means ensuring electricity generation and demand are balanced on a second-by-second basis. To do this we instruct flexible generation or demand close to real time through the Balancing Mechanism (BM) and contract ahead of time for balancing services where we have a firm requirement.

The BM enables the ESO to instruct (or dispatch) parties to increase or decrease their generation or consumption in the period between gate closure (one hour prior to real time) until the end of a Settlement Period (30-minute window).

The ESO has set out a roadmap of actions to facilitate wider access to the BM by 2020. Underpinning the roadmap is a desire for a BM that is open to all technologies and providers, with no significant barriers to entry (more information is available here). Increased participation will also significantly help the ESO manage operability challenges, and consequently lead to more cost-effective balancing actions.

The implementation of projects TERRE (Trans-European Replacement Reserve Exchange) and MARI (Manually Activated Reserves Initiative), the new pan-European reserve market platforms, will also be delivered in the future years. TERRE is expected to go-live in December 2019. This will widen access for GB flexibility providers to the European reserve market.

Imbalance and ‘cash-out’ price

Where a market participant generates or consumes more or less electricity than the volume they have contracted (traded), they are exposed to the imbalance price, or ‘cash-out’, for the difference. The party imbalance is calculated for each Settlement Period (SP) of 30-minutes.

The cash-out prices are designed to reflect the prices associated with the Balancing Mechanism Bids and Offers selected by the ESO to balance the energy flows in the Transmission System, as well as reserve scarcity. Therefore, there is an incentive on market participants to ensure the ‘residual balancing role’ of the ESO is minimised.

ELEXON apply the cash-out price to parties’ imbalances to determine their imbalance charges. For all Settlement Periods, the sum of all energy imbalance charges across all parties and accounts is calculated. This total amount of money need to be redistributed (or collected) and this is done via the RCRC.

The Task Force recognises there is an important link between the methodology and signal provided by the imbalance price and potential forward-looking signal to be provided by some element of BSUoS.

ENA Open Networks project

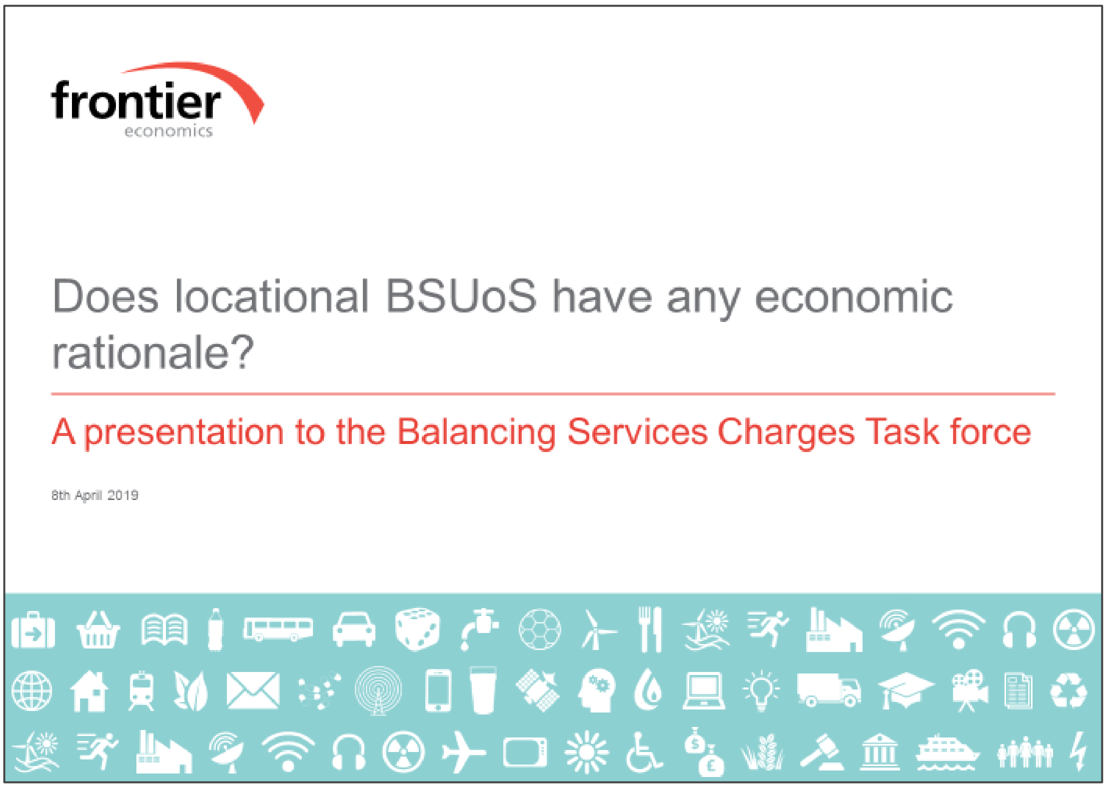
The Open Networks project is a major energy industry initiative that will transform the way our energy networks work, underpinning the delivery of the smart grid (more information can be found here). This project brings together 9 of UK and Ireland's electricity grid operators, respected academics, NGOs, Government departments and the energy regulator Ofgem.

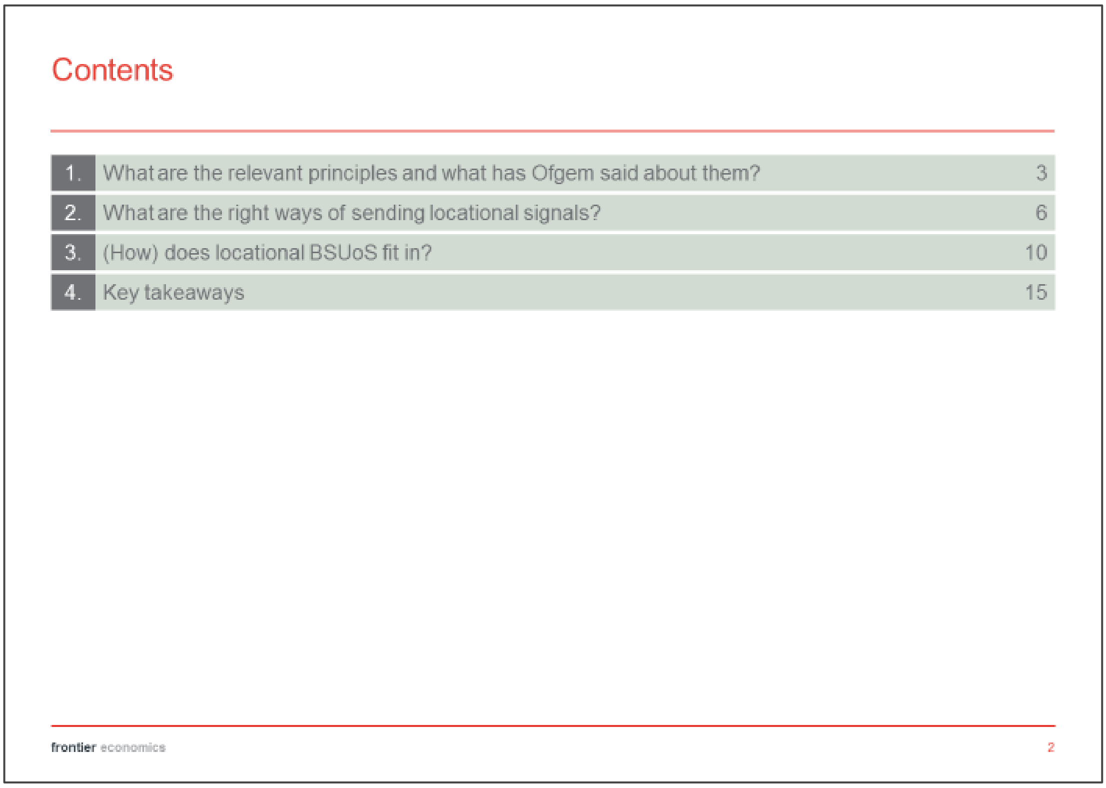
One of the objectives of the Open Networks project is to consider the charging requirements of enduring electricity transmission/distribution systems.

Settlement Reform

A key output of the SCR launched by Ofgem in July 2017 is the development of a Target Operating Model to deliver market-wide half-hourly settlement. The decision on when and how to require all suppliers across the market to be settled on a half-hourly basis for their customers will be made in the second half of 2019 and is subject to a cost-benefit analysis.

E. Frontier Economics analysis on locational BSUoS





Ofgem has made clear that cost reflective charges should be based on a concept of marginal cost…

Minimising total system costs

- Market participants should face the costs that they impose on the system
- They then take these costs into account in all of their investment and operational decisions.
- In other words, charges should be *cost reflective*

Cost reflective network charges

- To internalise costs in the decisions of market participants:
  - *forward looking costs* must be reflected: these can be changed by future behaviour; and
  - *incremental or marginal* costs, not average costs
- No meaning to 'cost reflectivity' in relation to *historic* costs

Economic theory indicates that users will make the most efficient decisions about where, when and how to use the network when they are facing the incremental or marginal cost of their behaviour. ***Ofgem, 2017 TCR consultation***

… and has stated that charges recovering any excess of total cost over marginal cost should be set to minimise the risk of distortions

Cost reflective charges won't recover sunk costs

- Natural monopoly networks: average cost > marginal cost
- Marginal cost tariffs will not recover total costs
- The *residual* needs to be recovered in the most efficient way possible

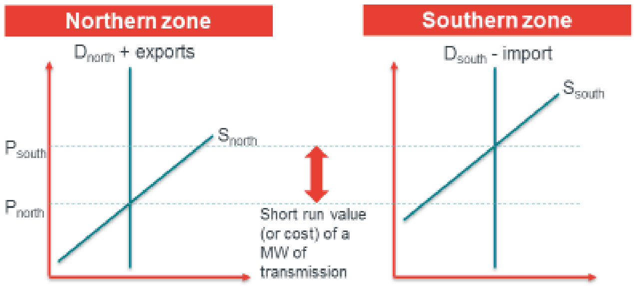
Cost reflectivity not relevant

- Sunk cost recovery charges not intended to generate incentives, but to recover irreversibly incurred costs
- Correct approach is to recover them in a way which minimises change in behaviour
- Recover charges from those who are not sensitive to price…
- … but fairness considerations also apply

> *Economic theory indicates that residual charges should be set in such a way to prevent the signals from the forward-looking charges from being distorted, so that users take account of the forward-looking signals to the greatest extent possible.* ***Ofgem, 2017 TCR consultation***

In relation to congestion, marginal costs can be reflected in zonal prices (SRMC based signals e.g. market splitting)…

Nodal or zonal prices mean that generation and load are incentivised to produce in an optimal way to minimise congestion*. Price differentials will also send a signal to invest in transmission.



<u>**In this stylised two zone example**</u>:

- All investments considered fixed (short run)
- Cheaper generation in the North exported to the South at the maximum capacity of "interconnector"
- Prices can't be fully equalised due to congestion on interconnector.
- Price differential reflects short run cost of transmission – it represents the value (or cost) of a MW of additional transmission i.e. incremental capacity would save customers the difference in prices
- The price differential sends locational signals for generators and load.

Wide recognition in Europe that market splitting has both pros and cons

* Note: In the GB market losses (which are also short run marginal costs of transmission) are already allocated locationally

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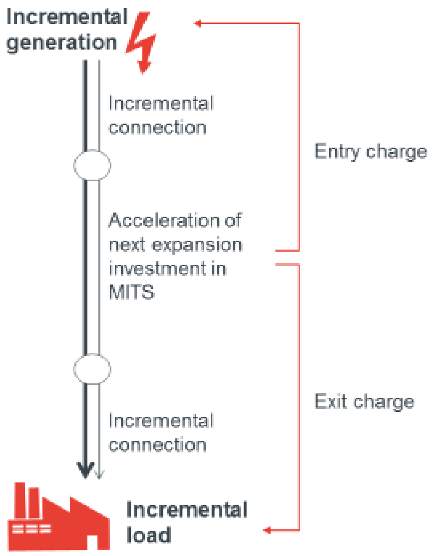
… or can reflect incremental investment costs (LRMC basis e.g. locational TNUoS)



<u>**In this stylised two zone example**</u>:

- Investments can vary (long run)
- Incremental generation results in new investments in transmission*
- Cost ideally measured by considering acceleration of transmission investment (PV effect)
- Sometimes approximated to cost incurred if next investment happened now
- Investment cost annuitized to derive annual cost, which is then divided into entry and exit charges which send locational signals to generation and load
- Energy price is then national, so redispatch required

* Note: Since investment costs relate principally to congestion, it may be considered reasonable to accompany long run marginal costs with locational allocation of the short run marginal costs of losses

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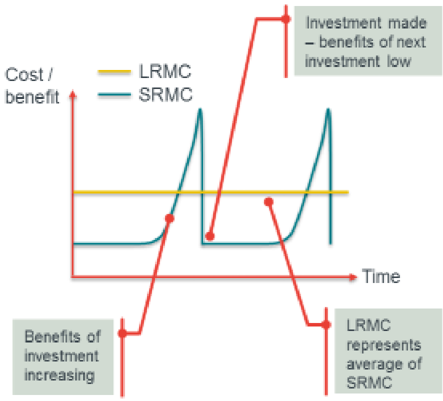
Under certain conditions, the two approaches are equivalent over time, so there is no logic to having both SRMC and LRMC signals

In this stylised two zone example:

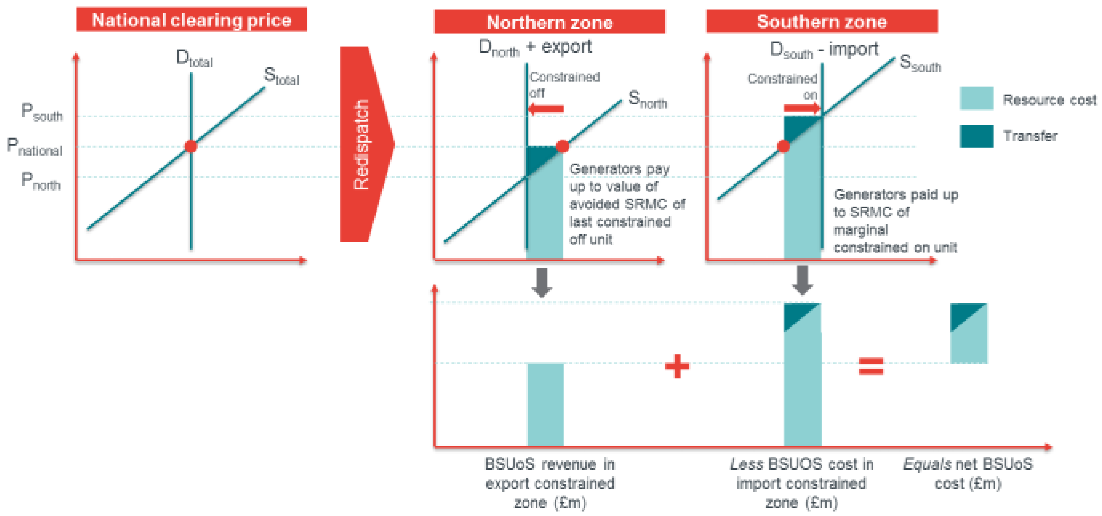
- Ideally, the transmission system should be expanded until the NPV of incremental benefit equals the NPV of incremental cost
  - The incremental benefit of expansion can be measured by the SRMC (i.e. the reduced despatch costs*)
  - The incremental cost is simply the LRMC
- So over time, if the system is expanded optimally, the NPV of SRMC based signals should equate to those of LRMC based signals
- This would result in zonal price spreads which follow a sawtooth pattern



A regime with both SRMC and LRMC approaches would risk double counting locational signals

* In fact, reduced despatch costs and changes in producer and consumer welfare – we ignore these for simplicity

The constraint cost element of current BSUoS represent the total cost of redispatch, comprising resource costs and transfers

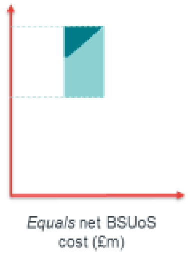


It is related to the price spread – but multiplied by the volume of redispatch, not the volume of generation/demand

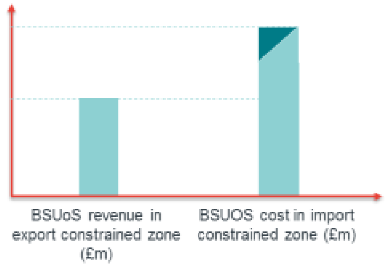
Ofgem should agree that allocating a total cost is unlikely to send efficient locational signals i.e. ones which reflect marginal cost

The BSUoS constraint cost in each half hour could be allocated in a number of different ways, however, it would only be by chance that it resulted in equivalent signals to zonal prices

1. Allocating net BSUoS cost *or* ***2. Allocating BSUoS revenues and costs***



- If net cost is charged to generators in the North (where zonal price would be lower) and customers in South (where price would be higher), then unit charge will depend on the quantity of in merit generation / load in the half hour
- As volume of in merit generation / load changes relative to constrained volumes, unit charge will vary
- It is not clear how this would provide a basis to pay generators in the South or load in the North

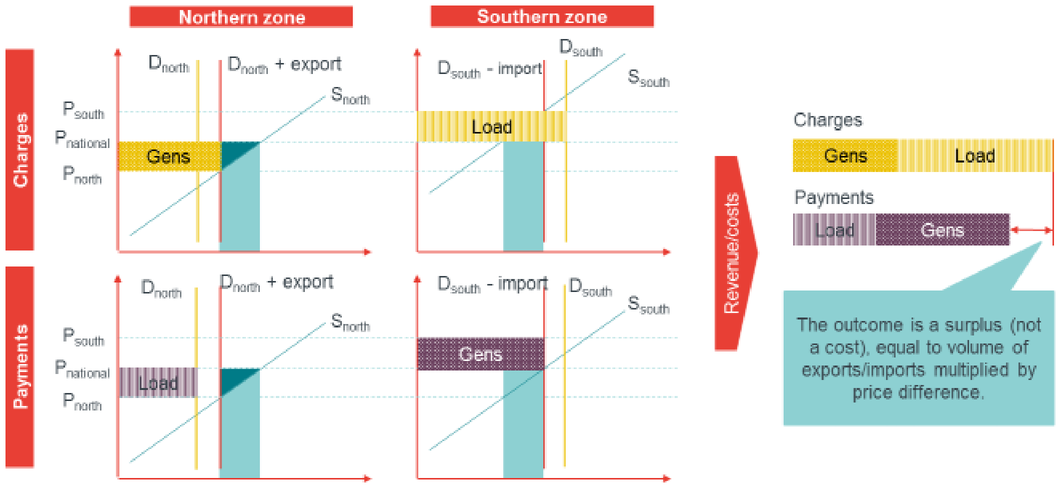


- BSUoS revenues earned in the North could be paid to generators in the South / customers in the North
- BSUoS cost could be charged to generators in the North / customers in the South
- Signals would be directionally aligned with zonal prices. However, again, level of charges/payments depends on the quantity of in merit generation / load in each zone. There is no reason to think this would reflect the marginal cost of congestion.

Furthermore, a simple two zone example ignores a key complication – how should total BSUoS net cost (or cost / revenue) be allocated between multiple constrained zones?

In theory there are a set of locational charges/payments which will mimic market splitting. However, they are unrelated to redispatch total costs.

This this is just a complicated (and ex post) way to get the market splitting result. However, it clearly shows that to achieve marginal cost signals the necessary set of payments and charges bears no relation to redispatch total costs.



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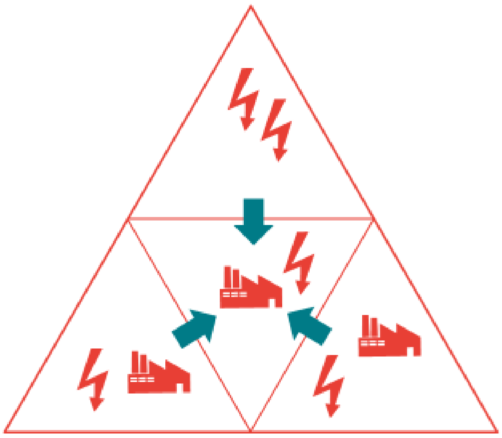
This conclusion can be demonstrated quantitatively via simplified modelling of a transmission system



1. Dispatch system to calculate zonal prices
2. Calculate national price and redispatch costs (and hence constraint element of BSUoS)
3. Test allocation methods to see if an efficient allocation BSUoS constraint cost element could be identified
4. If efficient allocation is found, "fast forward" in time (more transmission, more generation etc.)
5. Reperform 1 & 2, and show that allocation methodology no longer works

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Key takeaways

- Ofgem has clearly stated that **cost reflective charges should be based on marginal costs and that total cost recovery charges should minimise distortions** (see CMP 264/265 decisions and TCR consultation).
- **GB currently has theoretically justifiable locational signals** from the locational allocation of transmission losses and LRMC based TNUoS charges.
- According to Ofgem's own logic, the only **other theoretically justifiable basis for locational signals would be SRMC based signals**. These would need to be **instead of** **rather than** **as well as** **TNUoS charges**.
- There is a well **recognised way to implement SRMC based signals: market splitting.** It has both pros and cons.
- Ofgem has said that '*BSUoS may be changed to introduce incentives to influence forward-looking behaviour*'. But the **constraint cost element of BSUoS represents the total cost of redispatch**, comprising resource costs and transfers.
- There are an infinite number of ways to allocate this cost, but there is **no reason to believe that allocating a total cost will result in efficient cost reflective marginal cost based signals** (you would not start to think about efficient tariffs by looking at total costs).
- The level of charges/payments resulting from allocating redispatch total cost will depend on the quantity of in merit generation / load in each zone relative to the constrained on/off volume. The **charge/payment level will effectively be arbitrary**.
- There **is a set of payments and charges that would create marginal cost based signals, but they bear no relation to the BSUoS total cost** (and indeed, they will end up with a financial surplus rather than recovering a total cost).

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