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BALANCING SERVICES USE OF SYSTEM CHARGES

RENEWABLES IMPACT ANALYSIS

CLIENT:	RUK/SR
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Document History

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Notes

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Acronyms

Acronym	Full Term
BETTA	British Electricity Transmission Trading Arrangement
BM	Balancing Mechanism
BMU	Balancing Mechanism Units
BSC	Balancing and Settlement Code
BSUoS	Balancing Services Use of Systems charges
CMP	CUSC Modification Proposal
CUSC	Connection Use of System Code
DFFR	Dynamic Firm Frequency Response
DNO	Distribution Network Operator
DUoS	Distribution Use of System charges
EFR	Enhanced Frequency Response
GB	Great Britain
GDUoS	Generator Distribution Use of System charges
GSP	Grid Supply Point
MW	Mega Watt
MWh	Mega Watt hours
NGESO	National Grid Electricity System Operator
NGET	National Grid Electricity Transmission
NPG	Northern Power Grid
RUK	Renewables UK
SEPD	Southern Electric Power Distribution
SHEPD	Scottish Hydro Electric Power Distribution
SHET	Scottish Hydro Electric Transmission
SPT	Scottish Power Transmission
SO	System Operator
SR	Scottish Renewables
TCR	Targeted Charging Review
TNUoS	Transmission Network Use of System charges
TSO	Transmission System Operator
UKPN	United Kingdom Power Network
VAr	Volt Amps reactive

Acronym	Full Term
WPD	Western Power Distribution
XE	Xero Energy

Executive Summary

Introduction

Xero Energy has been commissioned by Scottish Renewables and Renewable UK to assess the current suite of change proposals relating to Balancing Services Use of System charges (BSUoS), how the changes might impact on the renewables industry and consider policy position in response.

Current arrangements

Currently, BSUoS is charged on a socialised basis to generators and suppliers. It is not charged to interconnectors and embedded generators (in the main) get paid BSUoS for offsetting demand. The charge is levied on a volumetric basis (£/MWh) and is calculated by National Grid Electricity System Operator (NGESO) for each half hourly settlement period. In 2017 the charge was £2.63/MWh based on a time average over the year. The charge is made up of costs for balancing the transmission system and determined based on the total volume of chargeable energy (i.e. output from transmission connected generation and demand from suppliers). In 2017, XE estimates that renewable energy projects were liable for £110m of BSUoS charges but benefitted from £96m of 'BSUoS avoidance' embedded benefits. The charging regime for BSUoS has been stable historically, with various previously proposed code changes stalled or rejected for various reasons.

Proposed changes

Several changes to how balancing costs are recovered have been proposed through the various ongoing regulatory workstreams, namely Ofgem's Electricity Network Access project, Ofgem's Targeted Charging Review (TCR) Significant Code Review, industry launched CUSC modifications (CMP307 and CMP308) as well as the newly instigated NGESO-led BSUoS task force. Key change themes across each of these workstreams include: removal of 'BSUoS avoidance' embedded benefit, application of BSUoS charges to all embedded generation (not just 100MW+), introduction of forward-looking (e.g. locational) charge elements and removal of non-forward-looking charge elements from generators.

Potential impact on renewables

XE has assessed the impact of some possible outcomes based on 2017 data:

- CMP307 (gross BSUoS charging for suppliers). Outcome is removal of embedded benefit and charge applied to all embedded generation. This change would increase network costs (and reduce benefits) for renewables by £177m. This is made up of **increased** costs for embedded projects and a **reduction** in costs for transmission connected projects.
- CMP308 (removal of BSUoS from all generation). Outcome is removal of embedded benefit but also removal of BSUoS charge from all generation, including embedded generation. This change would **decrease** network costs for renewables by £14m. This is made up of increased costs for embedded projects and a reduction in costs for transmission connected projects.
- BSUoS taskforce. Likely outcome from this taskforce is not clear, but XE considers that any move to introduce 'forward-looking' charges is likely to disadvantage renewables compared to other generation types given the cost makeup of balancing services (constraint costs, frequency response, reserve) which could be argued to be driven by renewables and intermittent generation more than other types of generation.

Recommended actions

Key recommendations are:

- Respond to TCR to resist removal of BSUoS avoidance embedded benefit by providing an evidenced consultation response. Albeit likely to be challenging.
- Seek to engage with NGESO BSUoS task force – SR/RUK likely to have good opportunity to influence outcomes if engaged with this process.
- Seek to engage with CMP307/308 working groups as and when progressed.
- Consider direct engagement with regulator given potential scale of impact of changes.

1 Introduction

1.1 General

Xero Energy Limited (XE) has been commissioned jointly by Renewable UK (RUK) and Scottish Renewables (SR) to assess the potential risks and opportunities associated with currently proposed changes to Balancing Services Use of System charges (BSUoS).

Several changes to how balancing costs are recovered have been proposed through the various ongoing regulatory workstreams, namely Ofgem's Electricity Network Access project, Ofgem's Targeted Charging Review (TCR) Significant Code Review, industry launched Connection and Use of System (CUSC) modifications (CMP307 and CMP308) as well as the newly instigated NGESO-led BSUoS task force. Key change themes across each of these workstreams include: removal of 'BSUoS avoidance' embedded benefit, application of BSUoS charges to all embedded generation (not just 100MW+), introduction of forward-looking (e.g. locational) charge elements and removal of non-forward-looking charge elements from generators.

1.2 Scope and aims

The aim of this report is to:

➔ Provide impact assessment of proposed changes to identify key risks/opportunities to help support RUK/SR to develop a policy position and response strategy.

Proposed thought piece to cover the following topics:

- Introduction to BSUoS and the current charging arrangements
- Summary of possible changes to BSUoS that have been raised, with commentary on likely outcomes for transmission connected generators/storage and embedded generators/storage:
    - Locational pricing – forward looking BSUoS charges
    - BSUoS avoidance embedded benefit
    - Removal of BSUoS charge for generation
    - Removal BSUoS charges on storage imports,
    - Removal of BSUoS charges on imports for virtual lead parties
- Views on likely upcoming change process (next steps) and timeframes.
- Identification of the key risks / opportunities for renewables industry.
- Recommendations for lobby/engagement.

1.3 Report layout

This report is organised with the following layout:

- Section 1 Introduction
- Section 2 Existing BSUoS charging methodology
- Section 3 BSUoS charging base
- Section 4 Potential methodology changes
- Section 5 References

2 Existing BSUoS charging methodology

2.1 Introduction

This section of the report provides a brief overview of the existing methodology used to calculate the BSUoS charges.

2.2 BSUoS price costs components

The key costs that are included within the BSUoS price [1]:

- Total costs of the Balancing Mechanism
- Total Balancing Services Contract costs
- Payments/receipts from NGESO incentive scheme
- NGESO internal costs of operation the system
- Costs associated with contracting for and developing balancing services

The BSUoS charge is made up of internal and external balancing costs. Figure 2-1 presents an overview of the costs that are included in the makeup of the BSUoS charge by NGESO.

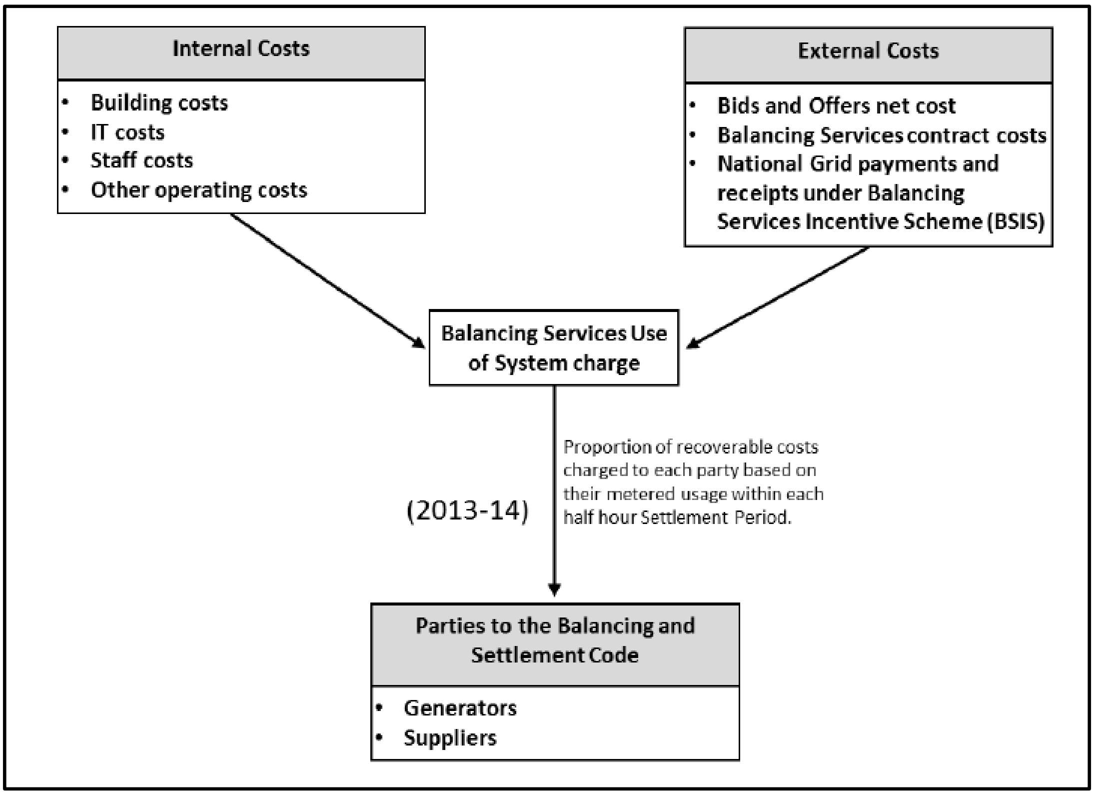

Figure 2-1: BSUoS pricing [2]

The external costs presented in the figure above include various costs associated with system operation. As well as including costs associated with residual energy balancing, these costs relate to the provision of services associated with various technical aspects of network operation including constraint voltage control, frequency management and contingency planning.

2.3 BSUoS charge

The BSUoS charge calculation is captured in Section 14 of the CUSC. BSUoS charge is calculated on the following key basis:

- Volumetric charge – per MWh of energy delivered or taken from the transmission system.
- Price determined ex-post based on the outturn costs, once known.
- Price determined for each individual half hourly settlement period and significant variability between periods.
- Socialised cost – single price calculated for all network users.
- Charge levied on generators and suppliers.
- Charged on a net basis to suppliers under GSP groups – export from embedded generators gets netted off demand for the purposes of calculating BSUoS liability for suppliers.

NGESO recovers the actual costs it has incurred in each half hour settlement period after the event, rather than via a fixed tariff ahead of time. The BSUoS charge is calculated in accordance with the Statement of Balancing Use of System Charging Methodology as laid out in Section 14 of the Connection Use of Systems Code (CUSC) [3], with charges apportioned on a half hourly £/MWh basis as follows.

BSUoS charge = BSUoS Price [£/MWh] x BM Unit metered Energy Volume [MWh] x Transmission Loss Multiplier x Trading Unit Delivery Mode (+ or – 1)

BSUoS charges are levied on projects to account for differences in demand and generation and for embedded generators this means that a credit can be accrued for supplying local load under an importing Grid Supply Point (GSP) group <u>but a charge is levied if the GSP group exports</u>. This credit/debit varies every half hourly settlement period.

2.4 Parties liable for BSUoS charge

As stated in CUSC 14.29.4, all CUSC parties acting as Generators and Suppliers (excluding BMUs and Trading Units associated with interconnectors) are liable for BSUoS based on their energy taken from or supplied to the National Grid system in each half-hour Settlement Period.

The charge for suppliers is currently passed through on a net basis. In broad terms this means that all demand met by embedded generation is removed from the total volume of energy that is liable to pay BSUoS (i.e. the charging base). This reduces the overall liability that suppliers have for BSUoS, but conversely increases the overall BSUoS price.

2.5 BSUoS charging mechanism

BSUoS charges are levied on projects through the balancing and settlements process, captured under the Balancing and Settlement Code (BSC). Therefore, the exposure to BSUoS charges/payments will vary from project to project depending on which energy account that export/import is allocated within this process.

The BSUoS charge will be levied onto each generation site depending on the 'lead party' responsible for the export. The lead party must be a signatory to the BSC. This is generally the supplier/off taker for the project but can also be another third party or the project itself. For embedded generators it is almost exclusively the site supplier that takes responsibility for the export volumes and therefore accrues any 'BSUoS avoidance' benefit, of which generally around 90% of the value gets passed onto the generator.

2.6 Historic BSUoS prices

The chart below shows the monthly data produced by NGESO regarding the estimated spend and BSUoS price from 2013/14 to October 2018.

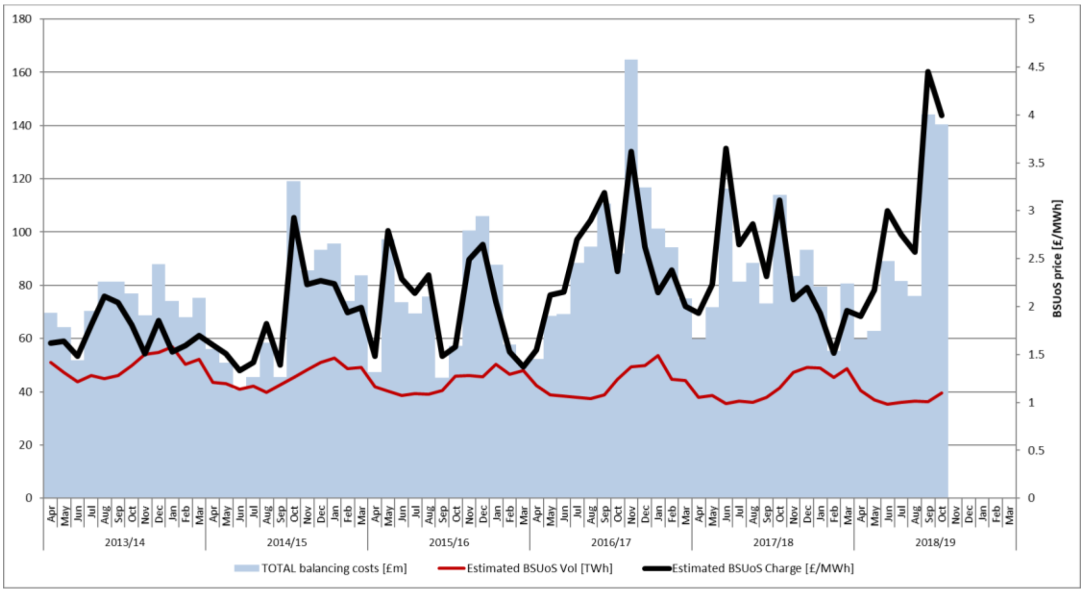

Figure 2-2: Historic annual spend on ancillary services [ref]

Based on half hourly data, the time averaged BSUoS price throughout 2017 was £2.63/MWh.

3 BSUoS charging base

3.1 Introduction

This section of the report provides an overview of the existing charging base for BSUoS, particularly in relation to renewable generation.

To provide some background to the analysis, XE has analysed the output from different types of renewable and non-renewable generator. The following information has been taken from NGESO's Future Energy Scenarios (FES) regarding the expected delivery/offtake of energy volumes from the transmission system.

3.2 CUSC parties

The overall BSUoS price, calculated for each settlement period, is determined by the total volume of energy supplied to or delivered by the transmission system. As described above, all CUSC parties are liable for BSUoS, except for interconnectors. Therefore, the charging base for BSUoS is influenced in different ways by different types of transmission system user.

- Energy output (and import) from transmission connected and non-exemptible embedded generation (100MW+) will be included as volumes liable for BSUoS.
- Energy demand across GB market will be included as volumes liable for BSUoS.
- Energy imports from and exports to interconnectors are volumes excluded from BSUoS liability.
- Energy output from licence exemptible embedded generation is not excluded from BSUoS liability but is included within the net volumes allocated to suppliers and therefore reduces overall demand volumes that are liable for BSUoS.

Currently, energy storage is treated in the same way as generation and therefore all energy imported/exported from these sites is liable for BSUoS. However, the treatment of energy storage with respect to BSUoS liability is the subject of an ongoing CUSC modification proposal – discussed in Section 4.3 below.

The remainder of this section of report provides some background to the overall volume of energy supplied to or taken from the transmission system by each of these key network user types.

3.3 Renewable energy – installed capacity

There are three broad types of generator classification which has a bearing on how BSUoS charges are levied:

- Transmission connected
- Distribution connected – licence exemptible (<100MW).
- Distribution connected – licensable (100MW+)

Transmission and distribution connected licensable generators are charged in the same way, whilst licence exemptible generation is treated differently. Based on the information published by the DNOs, XE has only identified three licensable embedded renewable generators already connected (excludes embedded transmission offshore wind):

- Blyth Wind Farm at 105MW.
- Lynemouth Power (Biomass plant) is also above 100MW, but distribution connected.
- An unidentified PV project in South Wales at 129.5MW, but not clear which project this is or if it is an error within the data.

3.3.1 Transmission connected renewables

Transmission connected generation. The table below provides an overview of the different types of transmission connected generation within the GB market. Note that this list also includes some embedded generation (i.e. projects with BEGA

Generator type	Transmission installed capacity (MW)			
	NGET	SHET	SPT	Grand Total
Biomass	1,989			1,989
Hydro	89	826		915
Wind Offshore	6,777	393	178	7,348
Wind Onshore	228	2,042	2,902	5,172
Grand Total	**9,083**	**3,261**	**3,080**	**15,424**

Table 3-1: Transmission connected renewable energy generators [4]

- Currently no PV projects are connected at transmission.
- Offshore wind has the most transmission connected capacity of any renewable technology, at over 7,3GW followed by onshore wind at approximately 5.1GW.
- Excluding biomass there is a broadly even split of installed capacity across Scotland and England and Wales

3.3.2 Distribution connected renewables (<100MW)

The table below presents an overview of the installed capacity of embedded, license exemptible renewable generators.

DNO	Installed capacity (MW)						
	Biomass	Hydro	Offshore wind	Onshore wind	Solar	G'thermal	Total
Electricity NW	5	8	0	344	118	0	**474**
NPG North East	70	0	8	524	75	0	**676**
NPG Yorkshire	126	3	0	707	125	0	**961**
SPD	54	129	24	1,673	17	0	**1,897**
SP Manweb	20	144	150	485	211	0	**1,010**
SEPD	0	0	0	9	1,283	7	**1,299**
SHEPD	54	33	0	2,129	30	0	**2,246**
UKPN EPN	197	0	88	416	1,419	0	**2,119**
UKPN LPN	0	0	0	5	12	0	**17**
UKPN SPN	25	0	0	82	387	0	**494**
WPD East Midlands	79	2	4	378	1,064	0	**1,526**
WPD South Wales	58	0	0	347	325	0	**730**
WPD South West	0	34	0	253	1,160	0	**1,447**
WPD West Midlands	16	0	0	38	481	0	**535**
Total	**702**	**352**	**274**	**7,390**	**6,707**	**7**	**15,432**

Table 3-2: Distribution connected renewable energy generators [4]

- Solar has the largest installed capacity for embedded, licence exemptible generation at 11.9GW followed by onshore wind at 8.6GW.
- Note that 'embedded transmission' connected projects have been excluded from this analysis.

3.4 2017 data

The overall volume of outturn energy associated with each of these types of transmission system user is illustrated in the figure below. The analysis below assumes that all energy volumes exported from embedded generation is from sites that are licence exemptible.

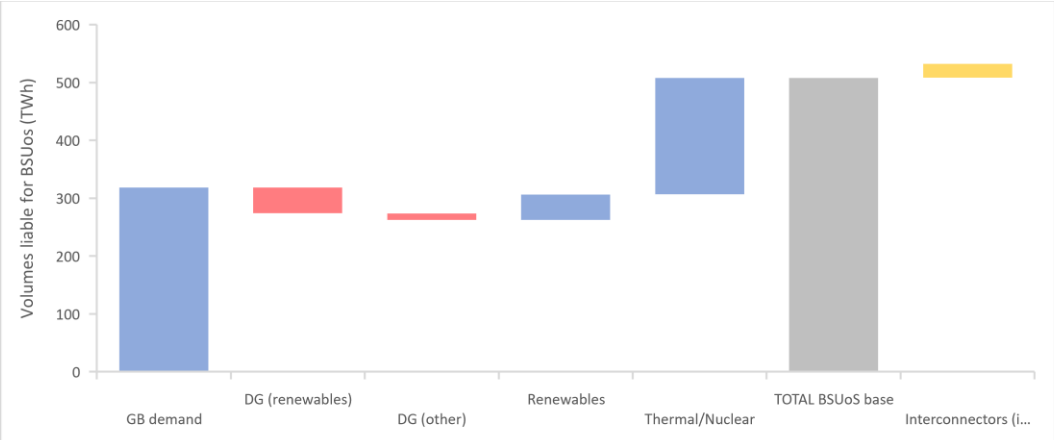

Figure 3-1: Volumes liable for BSUoS in 2017

- Total volume of energy liable to pay BSUoS in 2017 was approximately 508TWh.
- The export volumes from transmission connected renewables constituted around 9% of the total.
- The export volumes from distribution connected generators is predominantly from renewable energy technology.
- The total volume of exported energy from distribution connected renewable generation is very similar to the total volume of energy exported from transmission connected renewable generation
- In 2017, XE estimates that transmission connected renewable energy generators were liable for a total of £110m in BSUoS payments with onshore and offshore wind generation picks up the vast majority of these charges.

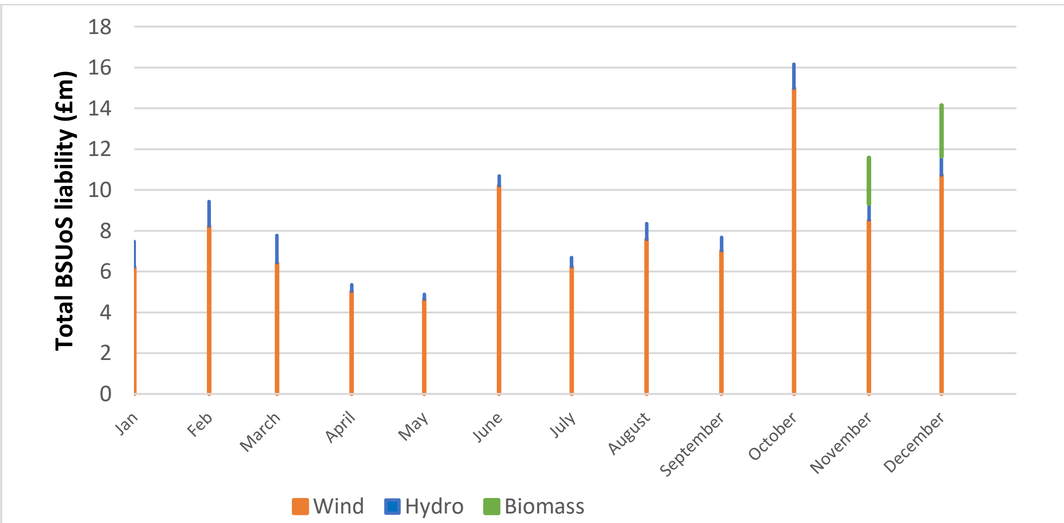

Figure 3-2: BSUoS charge liability for transmission connected renewable energy generators during 2017 [5, 6]

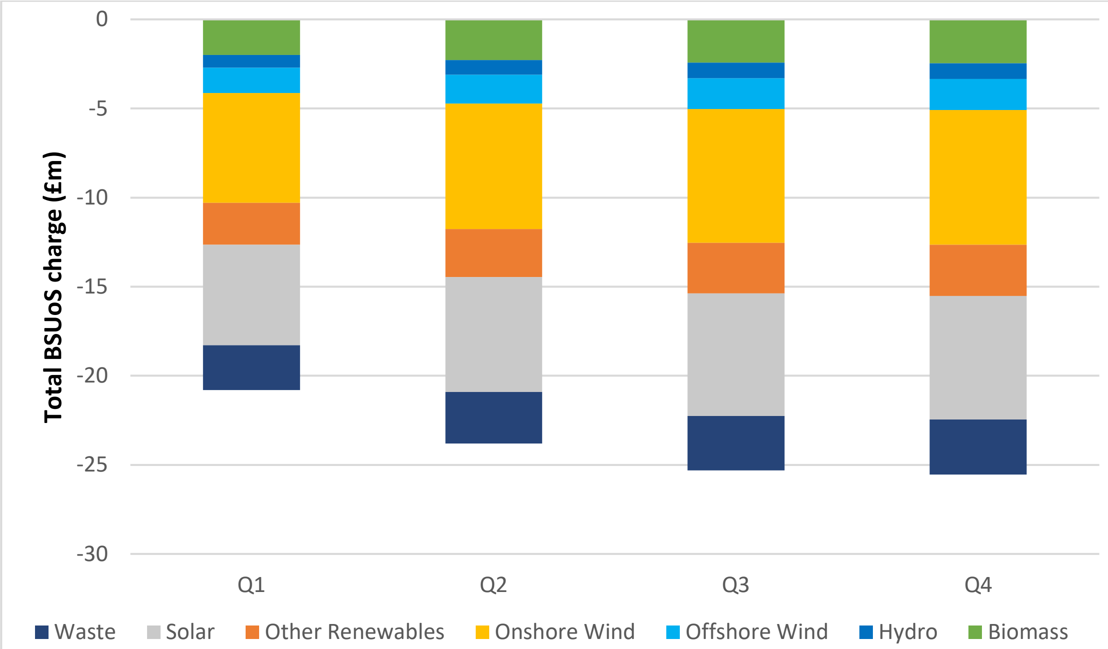

Figure 3-3: BSUoS charge liability for distribution connected renewable energy generators in 2017 [7]

- In 2017, XE estimates that distribution connected renewable energy generators were exposed to a negative charge (payment) of £96m in total for BSUoS payments. This includes waste and biomass.
- This estimate is based on the quarterly average BSUoS price and the estimated proportion of outturn embedded generation output from renewable generation using the FES.
- Note that this estimate ignores the delivery mode switching.
- Therefore, across all renewables the total liability for BSUoS is only £14m.

3.5 Forecast energy volumes relevant to BSUoS charging

3.5.1 Output from transmission connected generation

The figure below presents the expected change in output from transmission connected generation – renewable energy generators (onshore wind, offshore wind, solar and biomass) and 'other' non-renewable generators (all other types of generation).

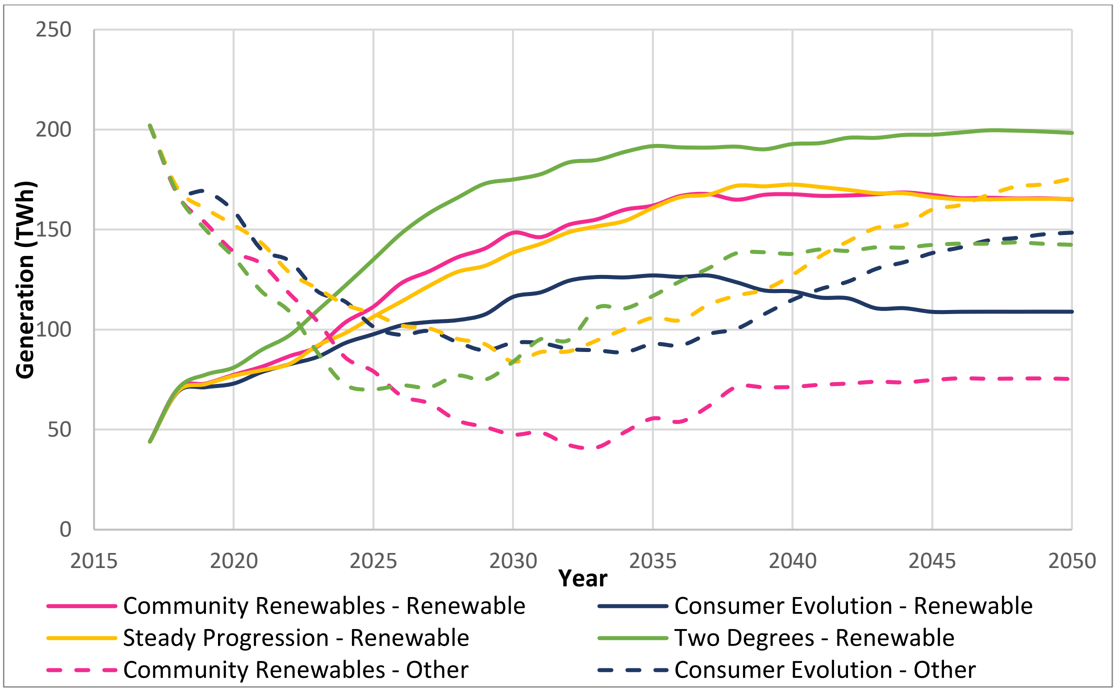

Figure 3-4: Forecast annual volume of energy output from transmission connected generation [7]

- In all scenarios, output from transmission connected renewable generation is expected to increase.
- In most scenarios, renewables are set to dominate the volume of energy delivered by transmission connected generation through the late 2020s and 2030s with other types of generator increasing again throughout the 2030s.
- An increasing share of energy volumes from renewable energy generators means that this cohort will become increasingly liable for balancing services costs, compared to other technologies.

3.5.2 Output from distribution connected generation

Similar to the transmission chart above, the total energy delivered by distribution connected generation – renewable and non-renewable is shown in the figure below.

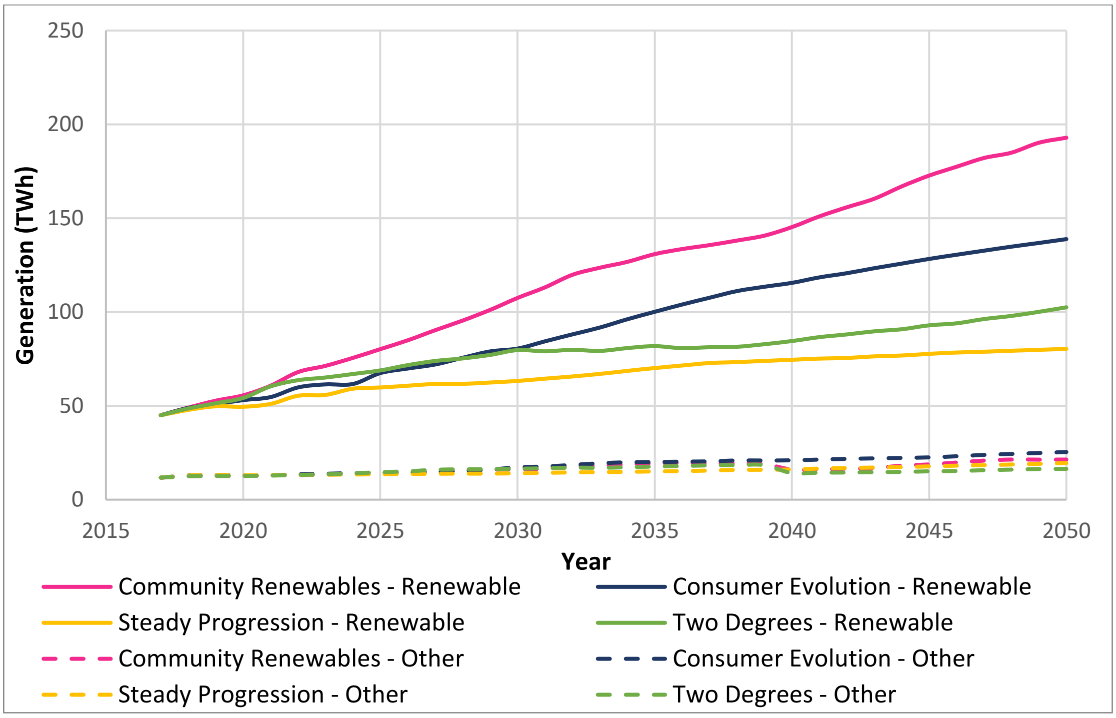

Figure 3-5: Forecast annual volume of energy output from distribution connected generation [7]

- Output from renewables already dominates energy volumes delivered by generators connected to the distribution system.
- Expected annual energy output from distribution connected renewable generation is expected to see growth under all scenarios.
- Output from non-renewable embedded generation is not expected to significant change in any scenario.
- Therefore, it follows that renewable energy generators are the main recipient of BSUoS avoidance embedded benefits.
- Increased energy output from embedded renewables will increase the overall embedded benefit seen by these projects and conversely continue to reduce the demand BSUoS charging base, pushing the BSUoS price up.

3.5.3 Underlying demand across GB system

The chart below illustrates the underlying annual energy demand across the GB network.

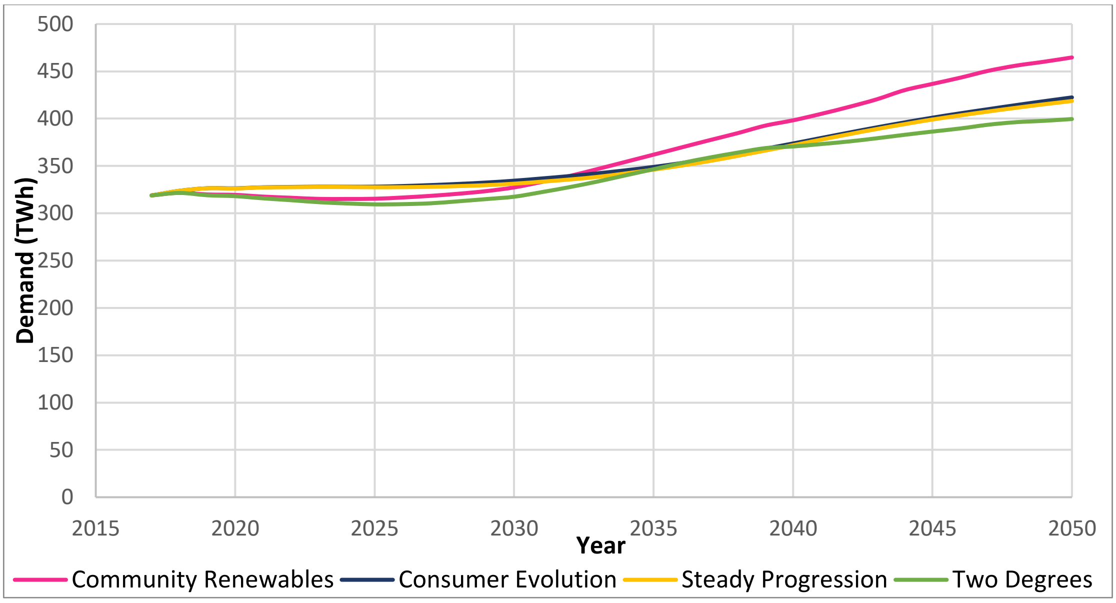

Figure 3-6: Forecast annual volume of underlying energy demand across GB [7]

- Overall demand is not expected to vary significantly in in any year throughout the 2020s.
- Significant demand growth is expected in all scenarios throughout the 2030s and 2040s.

3.5.4 Net flows from interconnectors

The figure below illustrates the volume of net flows from interconnectors.

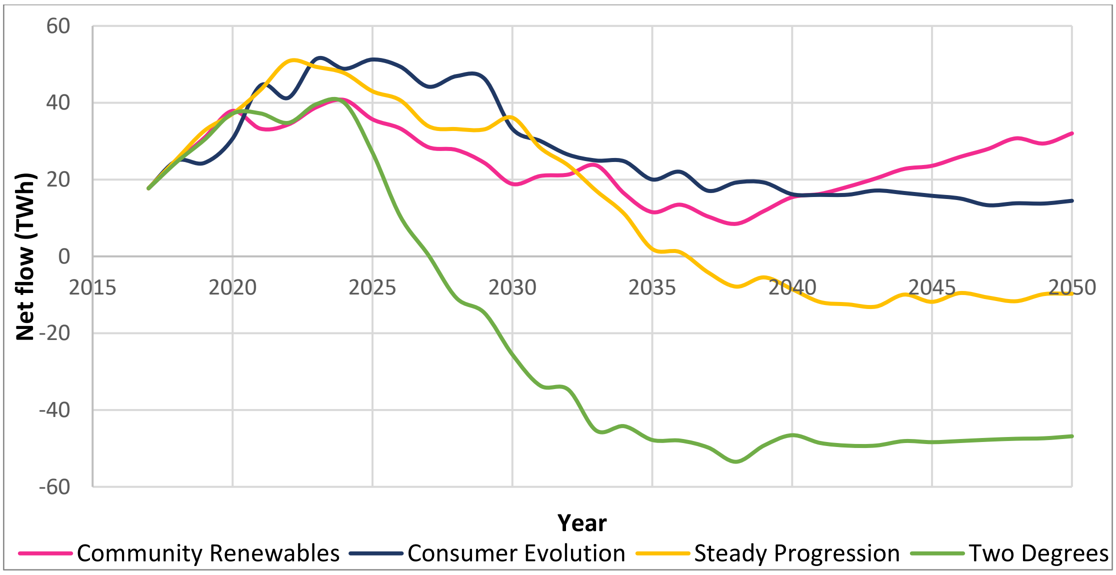

Figure 3-7: Forecast net annual flows from interconnectors [7]

- Net flows into the GB market are expected to increase in all scenarios and peak in the early-mid 2020s.
- Higher net imports from interconnectors will mean that the overall BSUoS charging base will reduce – increasing the BSUoS price in general terms for all other users (assuming that the energy imports are displacing transmission connected generators).

3.5.5 Import/export volumes from transmission connected energy storage

The figures below illustrate the total volume of energy expected to be imported by and exported from energy storage facilities.

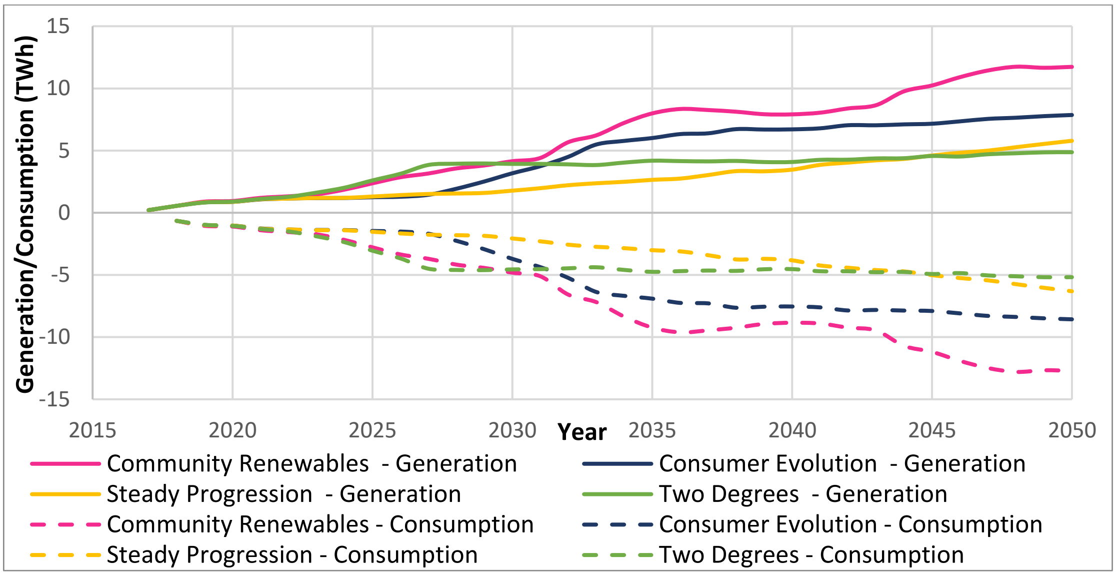

Figure 3-8: Forecast annual volume of energy imported to energy storage

- In all scenarios, the expected volume of energy imported/exported is expected to increase.
- More energy imported and exported from energy storage providers will re

3.6 BSUoS volumes

3.6.1 Total BSUoS charging base

The changing energy system dynamics described above have an impact on the expected charging base for balancing costs. Therefore, the chart below provides an indication of the expected annual volumes expected to be liable to pay BSUoS charges under each scenario.

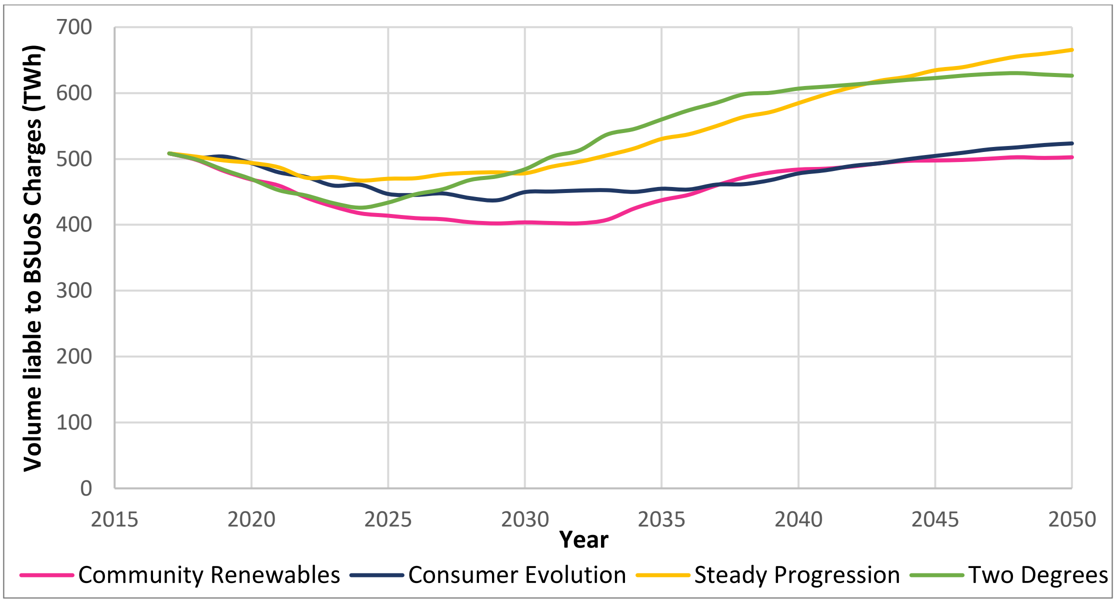

Figure 3-9: Forecast volume of energy liable for BSUoS charges

The breakdown of BSUoS liability under the Two Degrees scenario for 2050 is shown in the figure below.

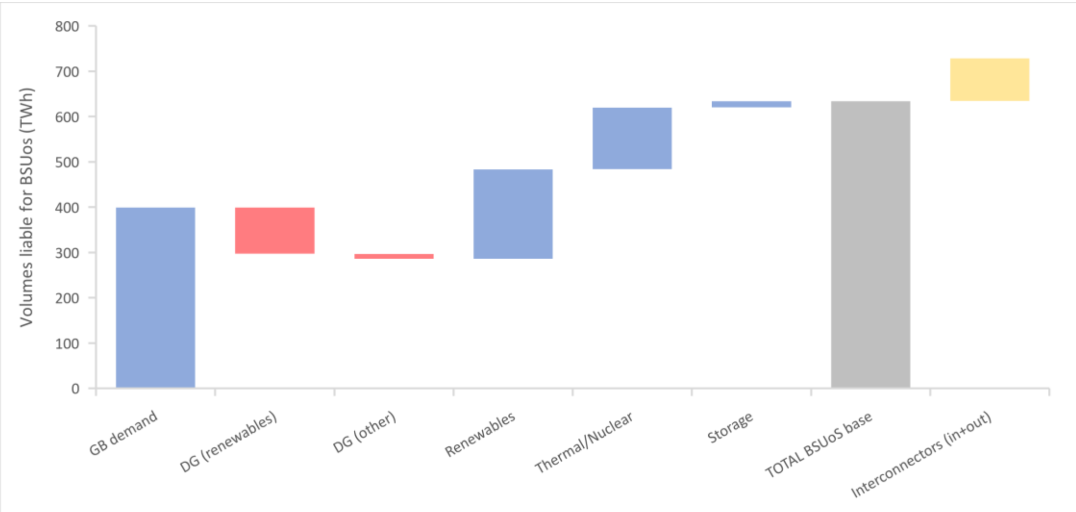

Figure 3-10: Volumes liable for BSUoS in 2050

The results above assume that storage is treated in the same way as distribution connected and transmission connected generation, respectively and continues to be liable for energy imports and exports.

3.6.2 Renewables proportion of BSUoS charging base

The figure below illustrates the overall proportion of the BSUoS charging base that is made up from energy delivered by renewables.

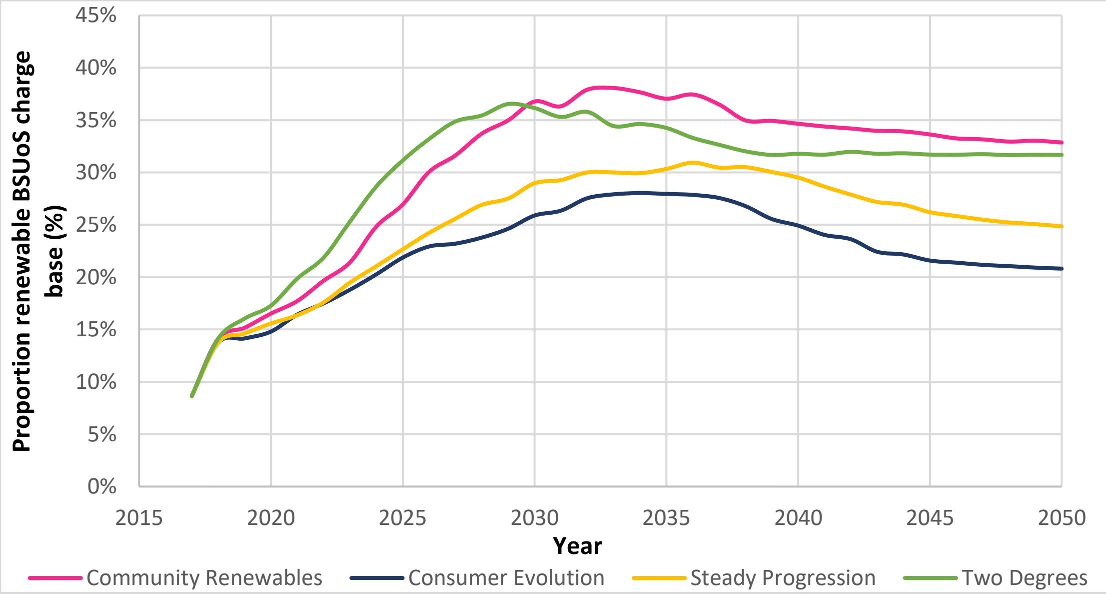

Figure 3-11: Forecast proportion BSUoS charging base made up from transmission connected renewables

- Renewables overall annual contribution to the BSUoS charging base is expected to increase for approximately 9% currently to between 28-38% by the mid 2030s.

4 Potential methodology changes

4.1 Introduction

This section of the report discusses the previous change proposals that have been progressed those that are ongoing and potential future methodology changes that could be brought forward. This section reviews the potential changes to BSUoS charges against the pre-existing charging regime. XE has calculated the impact of the proposed changes based on 2017 historic data.

4.2 BSUoS methodology change history

The methodology for calculating BSUoS charges has remained relatively stable over recent years, with few methodology change proposals. However, there have been some CUSC modification change proposals which have been brought forward in relation to BSUoS charging.

4.2.1 CMP262 (REJECTED) and CMP 250 (REJECTED) – price stability and visibility

BSUoS prices are calculated for each settlement period, ex-post, once the final outturn balancing costs and chargeable energy volumes for each period have been determined. This means that the BSUoS price is not known in advance.

BSUoS prices have become increasingly volatile in recent years, which has made it more difficult for generators to estimate their operating costs ahead of time. Two modifications were proposed in 2016 to try and address this issue – CMP262 and CMP250.

CMP262 was raised to remove balancing reserve costs from the calculation of BSUoS charges to reduce volatility and uncertainty.

CMP250 considered the ex-post charging principle of BSUoS and is proposing an ex-ante hedging arrangement for BSUoS costs to try and provide some certainty and stability regarding the BSUoS price. This modification was raised by Drax and would provide most benefit to thermal generators to assess more accurately their short-run marginal cost.

4.2.2 CMP296 (APPROVED) – Virtual Lead Party exemption from BSUoS

Project TERRE – the pan-European exchange system for replacement reserve balancing services – introduces the concept of Virtual Lead Parties. These new types of parties can provide replacement reserve services to NGESO (and other European TSOs) on aggregated basis from small, distributed generation.

CMP296 has been raised/approved to ensure that energy volumes (import/export) associated with Virtual Lead Parties are not liable for BSUoS, as the volumes are already liable for BSUoS charges through the site's normal energy account. This avoids double counting of imports and exports from sites providing these services and therefore doubling the BSUoS liability (or benefit). This modification was raised by NGESO, largely as a procedural change.

As Virtual Lead Parties do not yet exist within the current arrangements and this change relates simply to avoiding the double counting of volumes, this change is not expected to introduce any change in the expected baseline BSUoS price.

4.3 CMP281 (ONGOING) – removal of BSUoS charges on storage imports

4.3.1 Proposal overview

This modification was originally proposed by ScottishPower and is now being proposed by Drax to remove BSUoS charges for imported (off-taking) energy for licensed generators. The outcome of this modification proposal would be to reduce the charging base for BSUoS by excluding storage imports. Since the modification proposal has been launched, the scope of the proposed change is likely to evolve to include all generation (operated under a generation licence), not just storage facilities.

4.3.2 Impact on 2017

Based on 2017 data, XE estimates that the impact of this change would be to reduce the overall volumes liable to pay BSUoS charges by 0.74%, therefore increasing the BSUoS price by £0.0196/MWh (0.75%). This would therefore increase the revenue for embedded exemptible generators and increase the charge for transmission connected and embedded but licensable generators.

Based on the expected future increase in the role of storage, the impact of this change will increase over time.

4.4 CMP307 (SUSPENDED) – include embedded generation

4.4.1 Proposal overview

CMP307 was raised at the CUSC panel meeting in September 2018, by Engie. The purpose of the modification, according to the proposal submitted is "*to change the current collection of BSUoS from supplier and embedded exemptible generation to a methodology where BSUoS is charged on a gross basis and BSUoS is charged on export from embedded Exemptible generation.*" [8]

As this modification proposal is suspended there has not been any working group discussion or impact assessment progressed. However, the proposal sets out indicatively that "*the indicative benefit to consumers is up to £230m/year… made up of the removal of the current BSUoS embedded of £115m (collection from demand customers) which will be replaced by a charge of £115m on embedded generation.*"

This modification has been suspended due to the content being deemed to be within the scope of Targeted charging Review (TCR) significant code review [9].

4.4.2 Impact on 2017 BSUoS

Based on 2017 data, XE estimates that the impact of this change would be to increase the overall volumes liable to pay BSUoS charges by 22%, therefore decreasing the average BSUoS price by £0.48/MWh (18%). This change would therefore result in:

- A BSUoS price swing for licence exemptible embedded generation by £4.76/MWh as the BSUoS avoidance embedded benefit would reduce to zero and become liable for BSUoS at an average price of £2.15/MWh resulting in an increased liability of £214m.
- A decrease in the BSUoS charge liability for transmission connected and embedded but licensable generators of approximately £21m.

- Net BSUoS liability across all renewable generation will increase from the estimates 2017 value of £14m (in aggregate over transmission and distribution) to an estimated £191m.

4.5 CMP308 (ONGOING) removal of BSUoS from generation

4.5.1 Proposal overview

EDF has raised this CUSC modification proposal to remove BSUoS liability from generators altogether. This has been raised on the basis that generators connected to other networks throughout Europe do not need to pay equivalent charges for system balancing. This modification proposal is effectively a revival of the previous modification – CMP201 which was rejected by Ofgem.

The proposed legal text also removes export volumes from embedded exemptible generators from calculating the net BSUoS liability for each supplier. Therefore, removing the BSUoS avoidance

4.5.2 Impact on 2017 BSUoS

Based on 2017 data, XE estimates that the impact of this change would be to reduce the overall volumes liable to pay BSUoS charges by approximately 37%, therefore increasing the average BSUoS price by £1.56/MWh (59%). This change would therefore result in:

- Licence exemptible embedded generation would no longer be eligible for BSUoS avoidance embedded benefit.
- Removal of BSUoS charge liability for transmission connected and embedded but licensable generators.
- Net BSUoS liability across all renewable generation will decrease from the estimated 2017 value of £14m (in aggregate over transmission and distribution) to zero.

4.6 Targeted Charging Review (TCR)

In November 2017 Ofgem launched its targeted charging review (TCR) significant code review. The scope of this review is to look at 'residual' network charges and how these are levied on different customers and how the current arrangements might introduce 'distortions' resulting in higher costs for consumers.

On 28 November 2018, Ofgem set out its 'minded to' decision in relation to the TCR. The position taken by Ofgem has several impacts on renewable generator. In relation to BSUoS, Ofgem has set out its position as follows:

- Remove the BSUoS avoidance embedded benefit from distribution connected generators based on charging suppliers on the basis of net demand at each grid supply point.
- Charge BSUoS to embedded generation.
- That residual network charges should be charged to demand customers only.

Both of these points are the subject of the current CUSC modification proposals – CMP307 and CMP308, discussed above.

One impact of the proposals under the TCR is that it creates a significant differentiator between behind the meter and front of meter generation/storage deployment. Installations that are behind the meter will continue to see any benefits associated with BSUoS avoidance due to the reduced site import requirements. However, Ofgem states within the launch of task force that any elements of BSUoS which are simply cost-recovery (i.e. residual) could 'have potential for the TCR approach for cost-recovery charges to be applied'. Therefore, given the proposed 'fixed charge' or 'capacity charge' preferred approach to network residual charges set out in the TCR it is likely that this differentiator will not endure [10].

➔ **Behind the meter benefits relating to BSUoS charges are not likely to endure based on the outcome of the NGESO-led BSUoS task force.**

Depending on the outcome of the BSUoS task force, it is likely that any costs that are not deemed forward-looking will be deemed 'residual' and therefore not charged to generation through the principles set out in the TCR as Ofgem states that *'we consider residual charges should be levied on final demand users only, and… is our minded-to position'*.

➔ **Likely that any non-forward-looking balancing costs will be charged only to final demand customers going forward.**

4.7 NGESO BSUoS task force

4.7.1 Background

Another key outcome from the TCR is a proposed task force to consider the future of BSUoS charges. Ofgem has asked NGESO to set up a task force to 'do analysis to support decisions on the future direction of BSUoS charges' and 'in particular the potential and feasibility for some elements of BSUoS being made more cost-reflected'. Due to report findings in Spring 2019.

The task force will assess three things:

1. The extent to which elements of bs charge currently provide forward-looking signal that influences behaviour of system user.
2. Whether or not existing elements of balancing services charges have the potential to be made more cost-reflective and hence provide better forward-looking signals.
3. The feasibility of charging any identified potentially cost-reflective elements of balancing service charges on a forward-looking basis. It should also consequently identify the extent to which the different elements of bs charges should be considered cost-recovery charges.

Many other network charges are charged in such a way – for example Transmission Network Use of System Charges (TNUoS), Distribution Use of System charges (DUoS), Transmission Losses and distribution losses. BSUoS is unusual as an exception in this regard.

4.7.2 Possible changes

Balancing the transmission system is a complex task with many interrelated factors which need to be managed. The overall need (and cost) for system balancing is therefore a function of the network topology and operation as well as the way that the network is used by generators and demand customers.

Therefore, identifying the drivers for system balancing costs is a complex undertaking and not likely to result in a clear outcome. Nonetheless, some possible themes on forward looking charging that could emerge from the task force are detailed below.

Constraint costs

Network constraints are a function of limitations in power transfer capacity across main transmission network boundaries. These limitations are generally determined for any one or a combination of technical criteria: thermal capacity, voltage limitations or power stability limits.

Could be charged on a locational basis as these relate to regional network constraints which contribute to overall system balancing costs. For example, constraint payments to wind generators located in Scotland could be charged to those generators that are driving these costs – generation in Scotland. XE notes that Ofgem has specifically cited the example of network constraints driven by wind generation in Scotland within its task force launch letter [10].

Frequency response

Frequency response costs – Frequency response is required as a service to counteract normal variations in system frequency (instantaneous variations in supply/demand balance) as well as unexpected events which may result in sudden changes in the balance of supply and demand (e.g. interconnector fault). these costs could be allocated to different types of user. However, this is likely to be extremely complex. Some metrics that could be used to determine liability/cost driver may include:

- Contribution (or lack of) towards total system inertia (which helps to maintain network frequency). This is likely to penalise renewable generation most as most renewable projects are asynchronous machines which contribute little to system inertia and most large-scale thermal generation is synchronous which is the main source of system inertia.
- Size of infeed loss risk. Much of the cost of frequency response and reserve services are driven by the largest single unexpected generation/demand change risk to the network. Sudden changes to the generation/demand on the network will impact on frequency. Therefore, the transmission system is planned to ensure that any one single network or plant failing can't result in a sudden change of more than 1800MW. The largest network infeed risks in this regard are currently the fleet of nuclear generators. In future the largest infeed loss risks are likely to be next generation nuclear generators (i.e. Sizewell) and large interconnectors to continental Europe.

Reserve

reserve costs depend on various factors including the overall network requirements for reserve (flexibility) capacity across the system, forecasting accuracy/reliability, the availability of providers of flexibility throughout the year – both operating and/or available for dispatch by NGESO at short notice. An example of possible change that might be brought forward in this regard – possible that generators with higher uncertainty of output forecast in the near term (e.g. 24 hours ahead) are charged more for reserve services.

Reactive power

The requirement for reactive power on the system depends largely on the make-up of the network and the load flows. Transmission circuits with minimal loading are highly capacitive (export reactive power), whilst heavily loaded lines are inductive (import reactive power). These needs are met through the procurement of reactive power from generators as well as fixed assets (switched capacitor banks, shunt reactors or Static VAr Compensators) on the transmission network that can provide bulk compensation requirements.

However, as the network topology and system flows evolve, the need for reactive power will also evolve. For example, the reduction in load flows on the transmission system due to increased deployment of distribution connected generation has, in general, decreased the need for reactive power export to the system to reactive power import from the system.

NGESO's requirement for reactive power has altered significantly since 2005. The graphs below illustrate that the need for reactive power has swung significantly from a system that generally requires reactive power production (generators operating in leading power factor mode) to reactive power absorption (generators operating in lagging power factor mode).

This has occurred due to the changing utilisation of the transmission system – which is being used to transport less energy due to the increase in embedded generation.

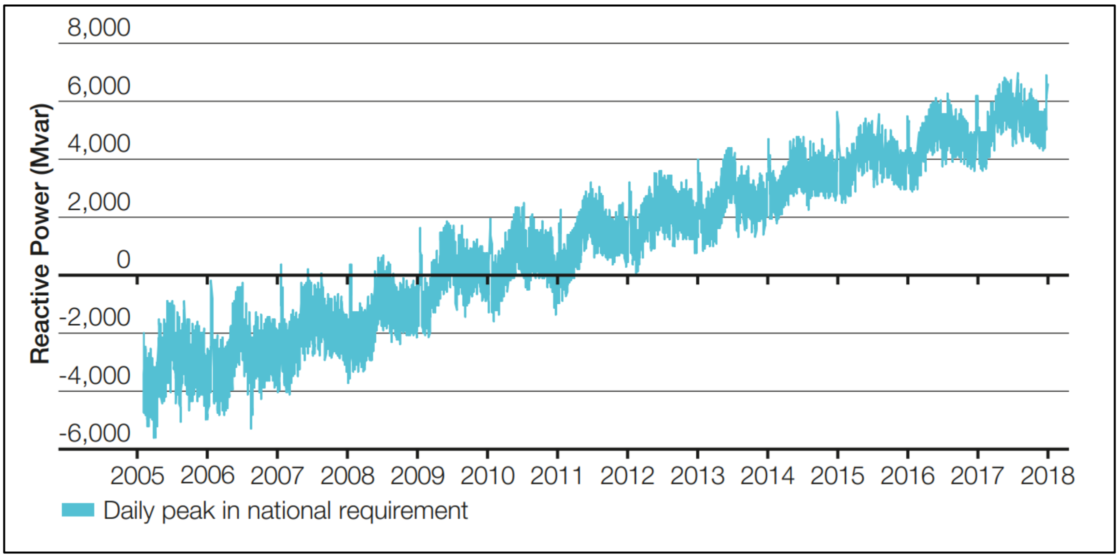

Figure 4-1: National daily peak reactive power absorption requirement [11]

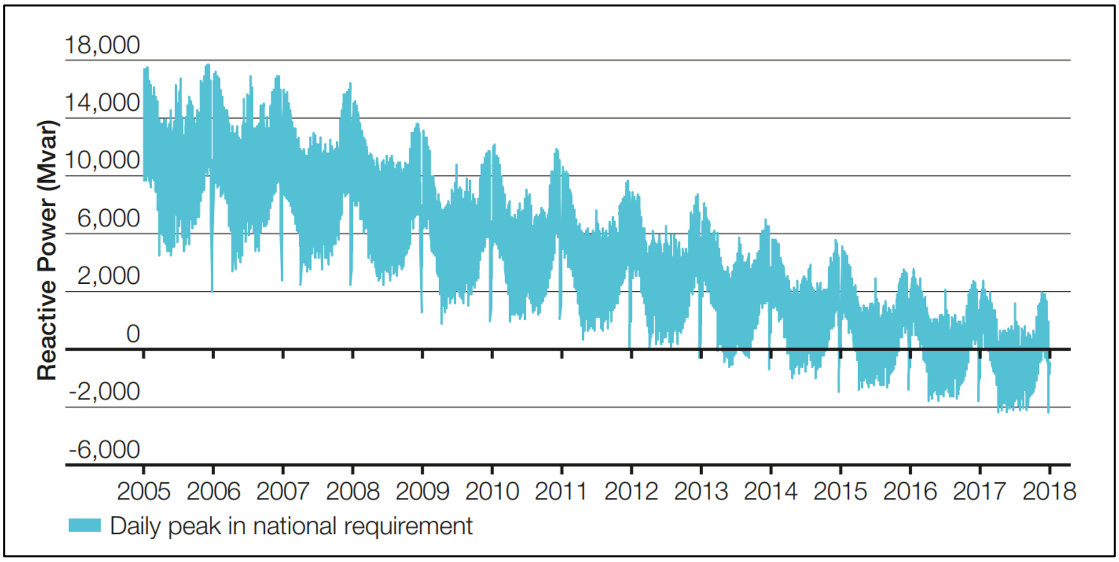

Figure 4-2: National daily peak reactive power production requirement [11]

Reactive power requirements are highly locational and therefore it is possible that some sort of locational charging could be applied to reactive power costs. However, the matter is complicated by the fact that reactive power services are performed by a mixture of network assets and generators.

Black start

It is not clear how black start services could be charged on a 'cost reflective' or locational basis and XE considers highly unlikely to be treated as such in any future BSUoS charging regime.

4.7.3 Likely impact

Quantifying in detail the potential impact of how these possible changes might impact on BSUoS charges for the renewables industry is beyond the scope of this report.

The overall charge (and ultimate cost to renewables) of any element of any locational balancing costs would depend on the way that the charging regime is designed. Charges could be levied on a volumetric basis (per MWh), like BSUoS or on the basis of network capacity (per MW) like TNUoS and GDUoS.

Nonetheless, balancing services costs are currently completely socialised and XE expects that any implementation of forward-looking costs would likely result in higher costs for the renewables industry.

5 References

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