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Transmission Charging Methodologies Forum & CUSC Issues Steering Group

12 September 2018

Welcome

Rachel Tullis, National Grid ESO

Housekeeping

- Fire alarms
- Facilities
- Red Lanyards

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Actions

TCMF Month	Requestor	Agenda Item	Action	Owner	Notes	Target Date	Status
Dec-17	PB	AOB	Make enquiries re missing website content specifically in relation to previous mods (TCMF members asked to advise when they come across any additional missing content)	RT	We are planning to get all archived modifications available on the website, however this will take some time due to the volume of material. Proposal forms, Workgroup reports, FMRs and decision letters will be uploaded. In the meantime any specific requests can be sent to the cusc.team@nationalgrid.com.	Oct-18	On-going
Aug-18	GG	AOB	Mike Oxenham to contact Garth Graham regarding Brexit discussion	MO		Sep-18	Complete
Aug-18	GG	Loss of Mains Protection Update	Find out whether LoMs change would have any impact on Black Start	GS	The proposed changes to Loss of Mains protection settings will significantly improve the stability of distributed generation for secured events during normal operation and for system restoration. Raising, and removing in some cases, RoCoF settings will reduce the likelihood that distributed generators will shut down inadvertently during the blocking loading process. Removing Vector Shift Techniques will reduce the likelihood that distributed generators will shut down inadvertently as network elements are energised. Therefore, the net effect of the proposed changes will be to enhance the potential value of distributed restoration capability, to simplify system restoration in general and to make the risk of needing system restoration lower.	Sep-18	Complete

Today’s CISG

Applying Power Available to the CUSC GC63

Today’s TCMF

CUSC Modifications Update

Align annual connection charge rate of return at CUSC 14.3.21 to price control cost of capital

[BSUoS 1 of 3] Taking Forward BSUoS Changes

[BSUoS 2 of 3] BSUoS Charging Change

[BSUoS 3 of 3] Issues associated with the net collection of BSUoS from the current charging base and within day price shape

Today's TCMF continued…

[Lunch]

CACM Cost Recovery

ESO response to Ofgem's Access and Forward Looking Charges Consultation

Location of TCMF

AOB

CUSC Issues Steering Group (CISG)

Applying Power Available to the CUSC

Intentions and feedback

William Goldsmith, National Grid ESO

Background

- The Electricity System Operator (ESO) procures commercial ancillary services such as **frequency response** (which is also a mandatory service) **and other reserve services** from generators, that are used to respond to unexpected deviation in supply or demand.

- Delivery **capability is dependant on level of headroom**, i.e. the difference between a generator’s maximum potential output and its current output.

- **Intermittent generators**[1] are unable to control their maximum output like conventional generators as it **depends on external factors** such as weather.

1. As defined by Intermittent Power Source in the Grid Code, e.g. wind, wave, solar

Grid Code Modification GC0063

- GC0063 addresses the issue of traditional MEL submission not being regular enough for intermittent generation with the introduction of the **Power Available signal.** This represents the dynamic, real-time maximum potential output from intermittent generation and **replaces Maximum Export Limit (MEL) in headroom calculations for Power Park Modules**.

- **MEL is redefined for Power Park Modules** as the registered capacity less unavailable Power Park Units.

- We believe that the **Power Available Grid Code change needs to be applied to the CUSC**, specifically where MEL is used to calculate De-Load.

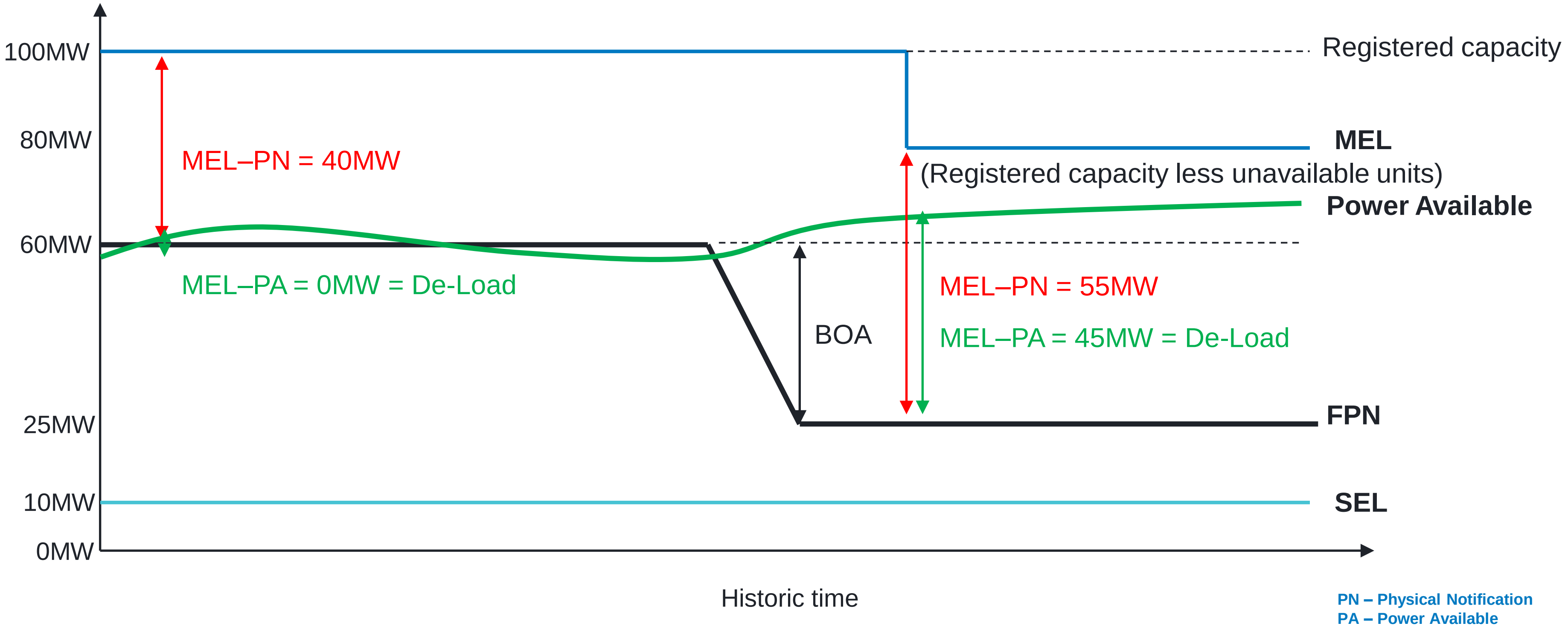
Our Intention

- We are looking at how to **apply the Power Available Grid Code change to the CUSC**.
  - An option would be: replacing MEL with Power Available for Power Park Module De-Load calculations.

- This area of work will facilitate response provision from intermittent generation (e.g. wind) by **allowing correct settlement calculations.**
  - All parties get appropriate payment based on their response delivery.
  - Historically wind has not provided response services, but wind is now increasingly likely to be the marginal plant and ability to dispatch will improve with PA integration.

- We believe this should **proceed straight to consultation**

Example - Power Available signal



PN – Physical Notification
PA – Power Available
FPN – Final Physical Notification
SEL – Stable Export Limit
BOA – Bid Offer Acceptance

TCMF CUSC Modifications Update

Joseph Henry, Code Administrator

New Modifications

CMP302 - Extending the Small Generator Discount

CMP302 looks to extend the Small Generator Discount until an enduring solution acknowledging the discrepancy between England & Wales and Scotland is implemented

Panel decided Modification would go to a workgroup

Urgency has been requested by the proposer

Code Administrator will source members

New Modifications

CMP304 - Improving the Enhanced Reactive Power Service by making it fit for purpose (SSE)

CMP304 looks to enable reforms to commercial reactive power services that will create more useful and economic solutions, and new opportunities for providers.

Panel decided Modification would go to workgroup

Code Administrator will source members

New Modifications

CMP305 - Removal of the Enhanced Reactive Power Service (ERPS) (NGESO)

CMP305 looks to remove EPRS

Panel decided Modification would go to Code Administrator Consultation

Code Administrator Consultation to be released once legal text finalised

Upcoming Working Groups

- **CMP280/281 – W/C 10 September 2018**

Removal of Demand Residual TNUoS and BSUoS on Imports for generators

- **CMP285 – September 2018 TBC – CA Cons closes 10 September 2018**

Independence and Diversity in CUSC Governance

- **CMP286/287 – 17 September 2018**

Improving TNUoS Predictability

- **CMP288/289 – 18 September 2018**

Delays and Backfeeds

Upcoming Working Groups

- **CMP291 – 11 and 12 October 2018**

Introducing the open, transparent, non discriminatory and timely publication of the harmonised rules for grid connection

- **CMP292 – 02 October 2018**

Advanced Fixing of Charging Methodologies

- **CMP295 – 17 October 2018**

To facilitate Grid Code compliance, and to ensure appropriate rights/obligations for Virtual Lead Parties

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Upcoming Working Groups

- **CMP298 – 02 October 2018**

Statement of Works

- **CMP300 – 25 September 2018**

Response Energy payment

- **CMP303 – September 2018 TBC**

Removal of additional TNUoS costs from local circuit expansion factors

Upcoming Modifications to Authority

- **CMP293/294 – W/C 10 September 2018**

NG Legal Separation

Workgroup Developments

- CMP280/281 – Workgroup held 30 August 2018. Progress made against original proposal an potential alternative. Next WG planned to finalise 281 WG Cons on 13 September 2018.

- CMP285 – CA Consultation closed 10 September. WG dates being sourced.

- CMP286/287 – WG held 17 August 2018. Further analysis ongoing. Next WG 17 September 2018.

- CMP288/289 – 1 workgroup held since last TCMF. Good progress made, with next due to be scheduled for October, consultation to follow.

- CMP291/295 – Modifications to be dealt with separately as per CUSC Panel. Dates in late September to be sourced.

Dashboard - CUSC

New Modifications	In-flight Modifications	Modifications put out for consultation/to authority	Modifications on hold
3	22	3	3

Modifications with Workgroups Held (August)	Authority Decisions	Modifications Workgroups Scheduled before October TCMF
7	2	10

Align annual connection charge rate of return at CUSC 14.3.21 to price control cost of capital

Lee Wells, Northern Powergrid

Align annual connection charge rate of return at CUSC 14.3.21 to price control cost of capital




Lee Wells
lee.wells@northernpowergrid.com

Connection charging methodology

Extract from standard condition C6 of the transmission licence

8. The connection charging methodology shall make provision for connection charges for those items referred to in paragraph 4 to be set at a level for connections made after 30 March 1990 which will enable the licensee to recover:

> *(a) the appropriate proportion of the costs directly or indirectly incurred in carrying out any works, the extension or reinforcement of the national electricity transmission system or the provision and installation, maintenance and repair or (as the case may be) removal following disconnection of any electric lines, electric plant or meters; and*
>
> *(b)* ***a reasonable rate of return on the capital represented by such costs****,*

and for connections made before 30 March 1990 to the licensee's transmission system, the connection charging methodology for those items referred to in paragraph 4 shall as far as is reasonably practicable reflect the principles of sub-paragraphs (a) and (b).

Broadly speaking, a Relevant Transmission Licensee can set its connection charging methodology so it can recover:

Its directly or indirectly incurred costs; and

A reasonable rate of return on those costs.

The defect

- Paragraph 14.2.1 of the CUSC states that connection charges enable a Relevant Transmission Licensee to recover the costs involved in providing the assets to connect to the transmission system with a ‘reasonable rate of return’.
- This rate of return is currently set at:
    - 6% for RPI-linked assets; or
    - 7.5% for MEA-linked assets.
- The 6% value was originally equivalent to the price control pre-tax cost of capital.
- As the price control cost of capital has fallen, this is no longer the case.
- This proposal does not consider the appropriate difference between the return on RPI-linked and MEA-linked assets (which is currently set at 1.5 percentage points).

Why change?

- The long-standing rates of return are not currently linked to the cost of capital the Authority has determined for a Relevant Transmission Licensee in its price control settlement.
- As the cost of capital has declined the calculation of the charges has remained linked to a 6% return (and 7.5% for MEA-linked assets).
- Aligning the rate of return in the charging methodology to the pre-tax cost of capital in the price control settlement in force at any given time would ensure that the annual connection charges levied by a Relevant Transmission Licensee reflect Ofgem’s latest view of a reasonable rate of return.
- This will result in a more cost reflective charges to Users.
- Failure to address this issue will result in a continued (and, based on current trends in the allowed cost of debt, growing) lack of cost reflectivity in the annual connection charge.

What needs to change?

- References to the rate of return in paragraph 14.3.21 of the CUSC ('The Statement of the Connection Charging Methodology') should be amended to define the RPI-linked rate of return as the pre-tax cost of capital determined in the relevant price control of a Relevant Transmission Licensee.
- We propose to retain the 1.5 percentage points delta for assets under the MEA revaluation method.
- The relevant value will update from year to year.
- Our proposed legal text will help to future-proof the drafting.
- It may be that a Relevant Transmission Licensee provides the system operator with the figure and publishes it such that Users can easily reference it (potential STC change).

How to derive the pre-tax cost of capital

- The pre-tax cost of capital calculation is proposed to be:

Pre-tax cost of capital = (1-gearing %) x pre-tax cost of equity + (gearing %) x cost of debt

Where:

Pre-tax cost of equity = post-tax cost of equity / (1 - corporation tax rate)

- Gearing and cost of debt can be sourced from the price control financial model (PCFM), as can the post-tax cost of equity.
- The product of this formula (plus 1.5% for MEA-linked assets) will replace the hardcoded 6% and 7.5% R_n term in the general formula in 14.3.21 of the CUSC.

Impact

- Aligning the rate of return to the pre-tax price control cost of capital will result in more cost reflective costs levied on the impacted Users.
- These more cost-reflective charges should ultimately be reflected in the charges seen by energy consumers.
- Ofgem’s network access consultation (‘Getting more out of our electricity networks by reforming access and forward-looking charging arrangements’), launched 23 July 2018, appears unlikely to consider the cost of capital used in calculating annual transmission connection charges.
- We do not believe this change will impact any existing or potential Significant Code Review (SCR) launched as part of the network access consultation, or any associated changes which may be led by industry as a result of the consultation.
- Ofgem’s developing RIIO-2 proposals are related in determining what the cost of capital will be in the next price control.
- This proposal does not impact that process; instead it is drafted to ensure the enduring Connection Charging Methodology remains aligned with the price control.

Taking Forward Changes to BSUoS Charging

Jon Wisdom, National Grid ESO

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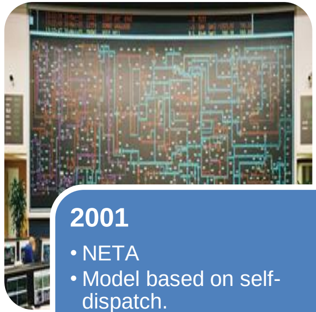
Why

Energy Market

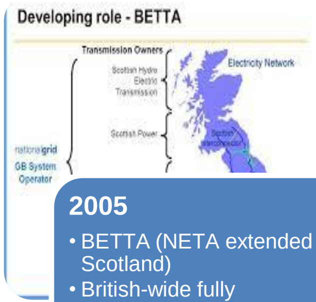
1990

- Electricity Industry Privatised
- Electricity Pool
- SO forecasted demand of every settlement period 24hrs ahead.
- Linear electricity system.



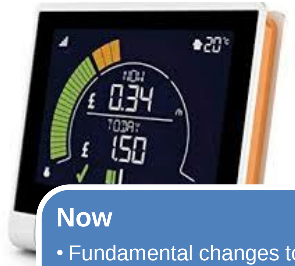
2001

- NETA
- Model based on self-dispatch.
- SO determines if generation and supplier positions will meet demand and then use the BM where it does not.



2005

- BETTA (NETA extended to Scotland)
- British-wide fully competitive market for the trading of electricity generation.



Now

- Fundamental changes to the system.
- Increasing volatility in BSUoS
- Government Policy
- Transmission vs distribution
- More challenge for the SO to keep the system in balance

- **ESO role requires a more holistic and longer term focus in order to enhance network and market access for all parties**

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Remaining Charging Elements

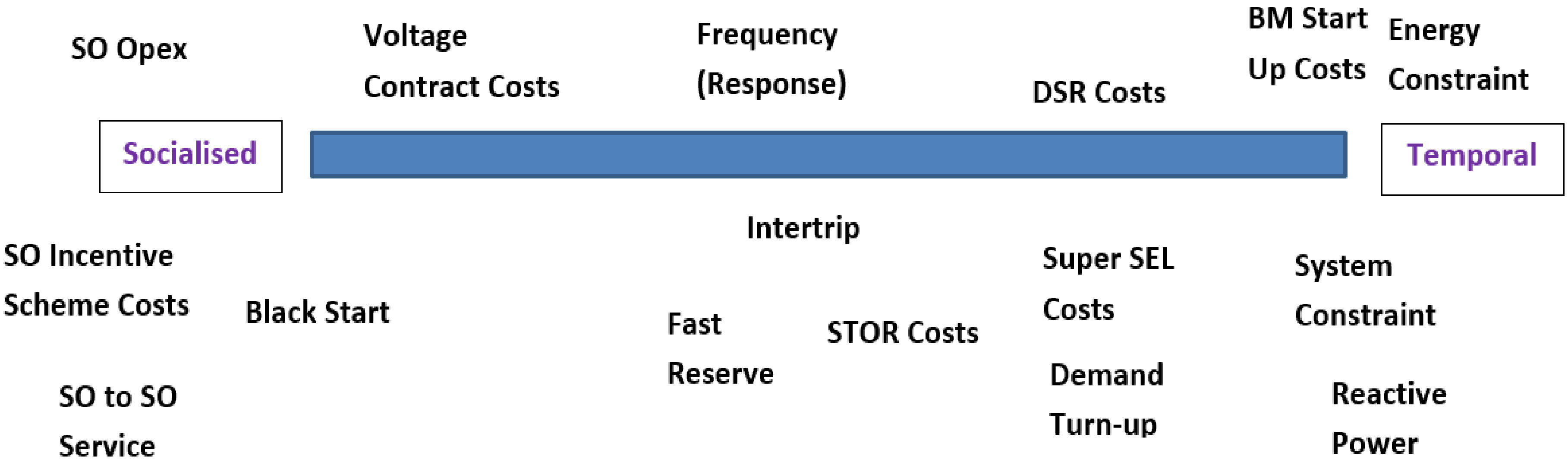
Operational costs
- How is BSUoS charged
- What is included in BSUoS
- Socialisation of constraints

Generation TNUoS signals
- Locational charging for generation
- Offshore connection charges
- Offshore local charges
- RIIOT2 implications on charging forecasts
- Treatment of Interconnectors

Treatment of new investments
- User commitment
- Treatment of new transmission investment

Not taken forwards
- Single network charge
- LMP / market splitting
- Longer term certainty in charging

BSUoS Cost Components



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Principles for consideration

HM Government

Proposed Way Forward

- **NGESO propose to run Workshops in Early October**
  - Similar to a BSC Issues Group
  - Take learning from CFF and Task Forces for engagement
- **Aim to raise a modification in October with input from across industry**

Any Questions

BSUoS Charging Change

Simon Vicary, EDF Energy

Proposed BSUoS change

12th September 2018

Summary

- We are concerned about the **current market arrangements not ensuring fair competition** between GB and other interconnected countries so have been considering options for reform.
- We are considering **raising a CUSC mod to only levy BSUoS on demand**, i.e. reconsider CMP201 in the light of new evidence and changed circumstances, as other interconnected countries in general levy similar costs solely on demand.
- This is **critical in the context of GB interconnection growth** which is set to significantly increase (4GW today, 8GW by 2020 - and, with Ofgem's approved pipeline, up to 18GW by early 2020s).
- **Ofgem broadly supported CMP201** but considered the short-term consumer negative impact outweighed the longer term benefits:

  "We consider that in principle, removing BSUoS from generators would have a small positive impact on competition. However, we are concerned that at this time the potential benefits this would bring would not be material enough to offset the potential costs to consumers from implementing the modification" - Ofgem decision Oct14

- **NGET's calculations**, on which Ofgem's decision was based, were that CMP201 would be detrimental to consumers - but **did not take into account the impact of CMP202** (Revised treatment of BSUoS charges for lead parties of Interconnector BM Units), so:
  - CMP201 modelling (for status quo) assumed BSUoS was split 50:50 between demand and generation.
  - As a result of CMP202 the G:D split for BSUoS charging in 2017 was around 49:51 and expected to be 47:53 by 2020.
  - This reduces the cost increase for suppliers to a value that is roughly equal to the reduction in GB wholesale prices.
- Our **modelling indicates that this change will leave GB consumers neutral** in the short term **with the potential for longer term consumer benefits from competition**.

Defect in current arrangements

- In our European trading partners and other interconnected countries the **equivalent charges for balancing activities are more commonly paid entirely by suppliers**.
  - As a result, the wholesale prices offered by generators in interconnected countries will not reflect these costs in the same way as those offered by a GB generator. (Our estimate is that GB generation is disadvantaged by the extra cost **~£600m in 2017**)
- Our proposal seeks to remove BSUoS charges from GB Generators, thereafter recovering all BSUoS from GB Suppliers. In doing so, it seeks to better facilitate **efficient competition between GB generation and generation in other interconnected markets**.
  - Better aligning the GB market arrangements and the charges faced by GB generation with those prevalent in other interconnected countries, where generation is typically not subject to such charges, allows GB and continental generation to **compete on a more equitable basis** and **removes the potential for BSUoS to distort cross border trade**.
  - **Supports the UK Industrial Strategy** for building a nation fit for the future with investment in skills, industries and infrastructure.
- The EU "Third Package" aims to deliver all consumers greater choice with more cross-border trade so as to achieve efficiency gains, competitive prices and security of supply.
  - It recognises that different market structures will exist, however it also acknowledges the need for fair competition across the European Community so as to provide producers with the **appropriate incentives for investing in new generation**.
  - Changing the GB arrangements as proposed thus facilitates the aims outlined in EU Directive 2009/72/EC concerning rules for the internal market in electricity.

Consumer benefits of change

- The proposed CUSC mod **better facilitates code objectives** (a) effective competition, (c) developments in transmission business and (d) EU compliance. It is neutral on (b) cost reflectivity.

- Consumer cost impact
  - demand BSUoS will be less than double of current BSUoS £/MWh rates as interconnector flows to GB do not pay BSUoS (i.e. split of BSUoS between demand and generation is not currently 50:50), i.e. **consumers neutral short term**.
  - sufficient **lead time of 2 years** after a decision is made to ensure
    - wholesale market adjusts to the removal of BSUoS from generation.
    - time for consumers and suppliers to adjust for change.
  - **benefit of avoiding** the need to factor **BSUoS risk** into generation/wholesale market costs, instead being covered within more predictable demand volumes.

- In the **long run** removal of a distortion in the wholesale market will ensure more effective competition which is in **consumers' interests**: i.e. will ensure investment in new generation is more efficient.

How does this BSUoS change fit with other reforms?

1. Ofgem's RAFLC:
- Proposes National Grid review of BSUoS costs to confirm whether they are 'cost recovery' or contain pricing signals
- Grid to lead review outside of SCR
- Timescales tbc

2. Ofgem's TCR:
- Considers addressing current BSUoS embedded benefit
- Impacts distribution connected generators
- Ofgem policy decision late 2018; industry mod to follow
- Apr 2020+

3. EDF Energy's BSUoS mod:
- Proposes to recover BSUoS costs from demand; reducing production costs to zero
- Industry code process
- 6 months process with 2 year implementation period, i.e. April 2021

Affects size of BSUoS by potentially changing scope (e.g. could determine some elements are price signals)

Affects how BSUoS is charged (e.g. could change to gross volumetric impacting embedded benefits)

Affect who pays BSUoS (i.e. change demand recovery to 100%)

CMP250 fixes BSUoS charges for long period to provide certainty to users.
This change is independent of the 3 above but appears more sensible if demand pays 100% of BSUoS.

CMP281 proposes to exempt import or export BSUoS costs from storage assets;
designed to align storage assets with generation

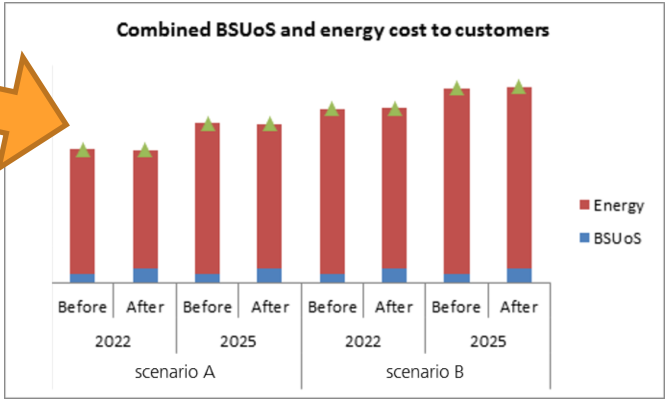
- **These are 3 separate policy considerations which can be progressed in parallel.**
- **The conclusion of 1) may impact the BSUoS "pot" but is unlikely to change the scale of materiality and urgency.**
- **National Grid should undertake a targeted 6 month review of BSUoS elements (Oct-March) to support overall timescale for BSUoS reforms**

CMP201 Modelling revisited

- An assumption of CMP201 was that BSUoS charges were split 50:50 between production and demand.
- Following CMP202 the production volume from interconnection is no longer liable for BSUoS charges and thus this assumption no longer held
- This assumption affects the modelled consumer impacts in the short-term identified by National Grid's modelling
- Revising this assumption means that the consumer impacts in the short-term are close to neutral
- The longer term benefits from more effective competition will remain.

The case for change has grown since CMP201:

	Interconnection (GW)	Interconnection volume (TWh)	BSUoS (£/MWh)
CMP201 (2012)	3GW (2GW to mainland EU)	10	£1.51/MWh
Now (2017)	4GW (3GW to mainland EU)	16	£2.48/MWh
Future	c.8GW 2020 c.18GW early 2020s	30-70TWh (2021-2025)[1]	Growing



[1] - BEIS, Updated Energy & Emissions Projections 2017 (January 2018) – Figure 5.1
https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2017

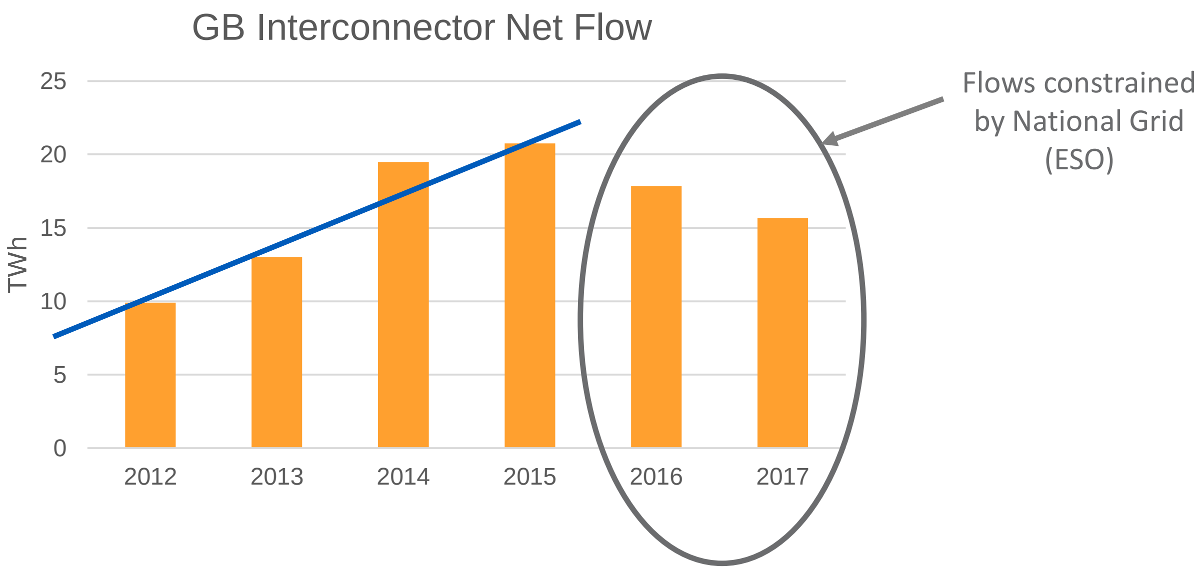
Next Steps:

- 12 September 2018 – Feedback from TCMF
- 28 September 2018 – CUSC Panel to raise modification
- H1 2019 – Ofgem decision
- Implementation – 2 years after Ofgem decision to give notice to market

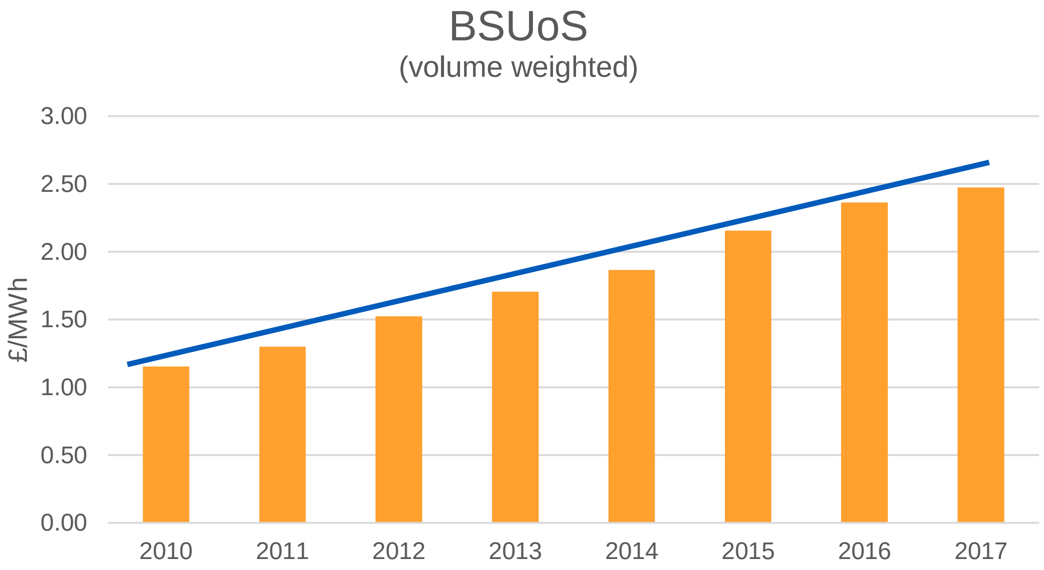
EDF ENERGY

Appendix

Change in interconnector flows since 2012



Historical BSUoS



Impact of BSUoS charged solely on GB demand

- Based on actual 2017 BSUoS data and modelling of interconnector flow changes the table below shows the estimated impact if BSUoS had been charged solely on GB demand.

	2017 Actual data	2017 with change implemented
Increase of GB generation due to proposed change (TWh)	0	2.1
GB chargeable BSUoS volume (TWh)	502.5	504.6
net imports (TWh)	15.7	13.6
Total GB demand (TWh)	259.1	259.1
BSUoS 2017 average (£/MWh)	2.48	2.46
Total BSUoS cost (£m)	1,243.9	1,243.9
BSUoS if charged 100% on demand (£/MWh)	4.80	4.80
Double current BSUoS rate (£/MWh)	4.95	4.95
Delta of BSUoS rate (£/MWh)	0.15	0.15
Minimum Wholesale Market fall to maintain status quo (£/MWh)	2.33	2.33
Consumer impact (£/MWh)		0.00
Consumer impact (£m)		0.0

Note: the minimum Wholesale Market decrease to maintain status quo is 15p/MWh less than the generation BSUoS rate.

Embedded Generation

- The impact on embedded generation of moving BSUoS recovery solely onto GB demand is expected to be neutral, as shown in the table below.

	£/MWh
BSUoS embedded benefit increase	2.33
Wholesale Market decrease*	2.33
Net Embedded Generator impact	**0.00**

*minimum Wholesale Market decrease to maintain status quo

Issues associated with the net collection of BSUoS from the current charging base and within day price shape

Simon Lord, Engie

BSUoS

Issues associated with the net collection of BSUoS from the current charging base and within day price shape

Three issues need addressing in the short term

1. **Move from collecting BSUoS from net supplier demand to gross demand**

   Removal of the netting arrangements will lower customer's BSUoS bills by around 10-15% by increasing the charging base. The current BSUoS embedded benefit of ~ £115m (collected from demand customers) will be replaced by a charge of £115m, placing embedded generation on the same charging basis for BSUoS as Transmission connected generation.

2. **Collecting demand BSUoS from end consumption**

   Collecting a predominantly residual charge from intermediate consumption (demand used in the production of generation e.g. storage and generation site load) has the effect of increasing power prices by more than the increase in demand BSUoS resulting from this. Intermediate demand recovers the cost by adding it to its generation sale cost at a marginal rate. Established economic theory supports this approach (e.g. VAT).

3. **Within day BSUoS shows higher overnight BSUoS cost (£/MWh) than day time**

   Overnight BSUoS charge rate (£/kWh) is roughly 50% higher than day time BSUoS rate driven by lower overnight demands. BSUoS cost (£ million) overnight do not reduce significantly during the overnight period as these are driven by increased cost of managing head and foot room and managing constraints during high wind conditions. The level of embedded wind further reduces transmission demand during these periods. This placed a high marginal cost on the remaining demand that further reduces overnight demand levels increasing the charge rate.

Move from collecting BSUoS from net supplier demand to gross demand

Defect

1. Charging of BSUoS to suppliers on a net basis results in a non-cost reflective benefit being gained by embedded generation. The BSUoS charge includes services that are needed by all consumers and all generators. These services are required to ensure system stability including reserve, response and voltage cost as well as system security services such as black start.. Around 10-15% of all generation is now being supplied from embedded sources who in general receive this as a benefit.

2. Inefficient dispatch: the marginal cost of embedded generation is reduced by ~£5/MWh, resulting in inefficient dispatch of this type of plant.

3. Raises costs to consumers:- P315 (Publication of Gross Supplier Market Share Data) details suppliers import and export meter volume. This shows around 46TWh of supplier export generation and 297TWh of supplier import demand. It is estimated that removing the netting arrangement and charging embedded export meters as generation will result in a fall of around 15% to the BSUoS tariff for all customers.

Collecting demand BSUoS from end consumption

- The residual element of BSUoS is currently charged to end consumption as well as intermediate consumption (storage and demand consumed by generation in the production of energy). This adds to the marginal cost of energy as generation demand will factor these costs into the wholesale price – end demand ends up paying these costs twice, increasing the cost of energy for end consumers

- A BSC metering solution will be required to differentiate energy used for generation purposes (storage and generation site demand) from behind the meter generation. Initial work by Elexon (see CMP 280/281) will be potentially useful in this context. In addition an adjustment to RCRC will be required.

- Optimal position is all BSUoS is collected from end consumption (as in most of the EU) with forward looking benefit/charge applied where demand/generation can influence the cost. We do not propose a change to the current 50/50 demand/generation spilt as this is will require a long lead time due to the effect on power prices set in existing contracts. Current SQSS designs optimises constraint cost and build cost, reducing the overall cost to all consumers as such is not considered as a forward looking charge but a function of the SQSS and TNUoS model.

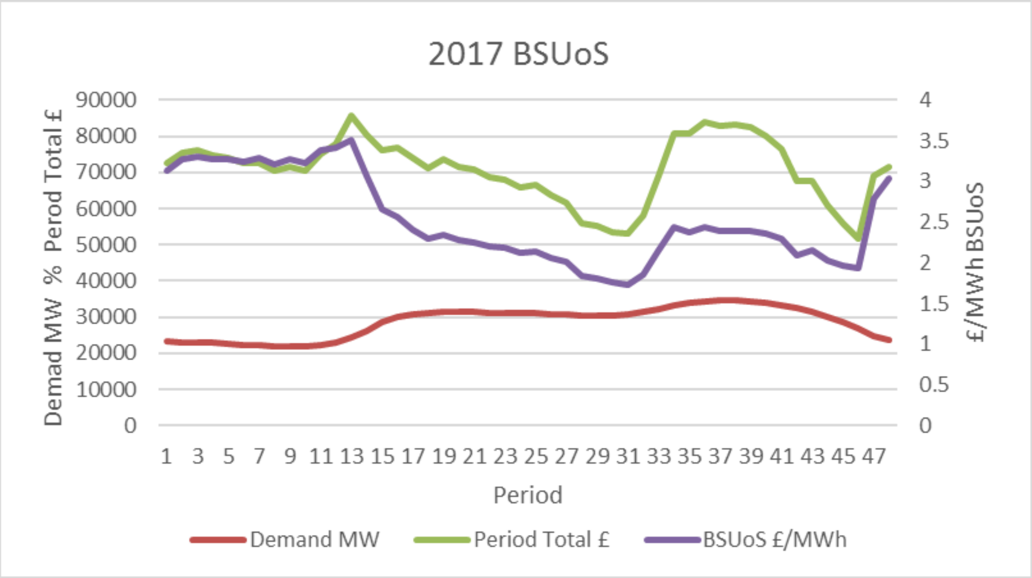
Within day BSUoS shows higher overnight BSUoS cost (£/MWh) than day time

(1) Customers that take power only overnight are paying a disproportionate cost towards the cost of managing the power system.

(2) Periods cost is similar day and night but it is recovered over a much smaller volume resulting in 50% higher BSUoS cost overnight.

(3) Creating head and foot room during lower demand periods is a key driver.

(4) Solution is potential a flat daily charge.



Forward Looking BSUoS charge

- Proposed solution should be mindful of developments in the being progressed as part of the Targeted Charging Review (TCR) and Charging Futures Forum (CFF)
- We note that a review may be undertaken of the forward looking element (potentially by the ESO). There is also significant interaction between TNUoS and constraint BSUoS as the level of constraint at transmission is set by the SQSS in the interests of all consumers.
- Any potential modification will leave a placeholder for this if required.

Appendix BSUoS data, Net to Gross indicative data from P315 data

BSUoS P315 data indicative data		
Demand weighted BSUoS	2017	
supplier export meters	-45,918,546	MWh
supplier import meters	296,841,715	MWh
Net supplier demand	250,923,169	MWh
BSUoS collected from import at tariff	£732.58	£m
BSUoS paid to embedded export via supplier	£113.32	£m
Demand BSUoS paid to NG	£619.26	£m
Revised just collect from Supplier import	£619.26	£m
BSuOS Gross base supplier MWh	296,841,715	
Demand weighted 2017 BSUoS	£2.47	
New BSUoS	£2.09	-15.47%
Annual extra COST £m (gen + demand)	£226.65	
Annuitised cost ~10 years) £m	£2,266.46	

CACM Cost Recovery

Urmi Mistry, National Grid ESO

CACM

- **Capacity Allocation and Congestion Management**
  - European Network Code
  - Central component of IEM
- Came into force 14 August 2015
- Aims to maximise the efficient use of interconnection and facilitate greater cross-border electricity trade through market coupling the day ahead and intraday timescales

CACM - Ofgem

- Ofgem need a mechanism for TSOs and NEMOs to recover costs associated with Market Coupling
- Initial consultation in March 2017
- Second consultation in June 2018
  - Decision due on their minded-to position soon
- Cost recovered through TNUoS
  - National Grid did not agree with this proposal
- Licence Change required

What are we planning to do

- NGESO aim to raise a modification between now and Jan 2019
- When we have more information on what this looks like
  - Initial thoughts, this will be similar to CMP283
- Clarify timescales with Ofgem

Any Questions?

Charging Futures Forum update
September

Rob Marshall, National Grid ESO

Overview of Forum

- Updates from
  - RIIO2
  - Targeted Charging Review
- Breakout sessions on Access and Forward Looking Charges consultation
- ESO role in wider reform
- Other high priority topics

All content used on the day is available on www.chargingfutures.com

Charging Futures

Consolidated timelines

Q3 2018 | Q4 2018 | 2019 | 2020 | 2021 | 2022

TCR

- Ongoing policy development
- Consultation on "minded-to" SCR decision (late 2018)
- Outputs raised as code modifications (spring 2019)
- Implementation from 2020/21 onwards

Access/ Forward-Looking Charges

- Consultation (closing 18 Sept 2018)
- Proposed SCR launch
- Options development, assessment and consultation
- SCR conclusions decision (2nd half 2020)
- Target first set of changes to take effect (April 2022)

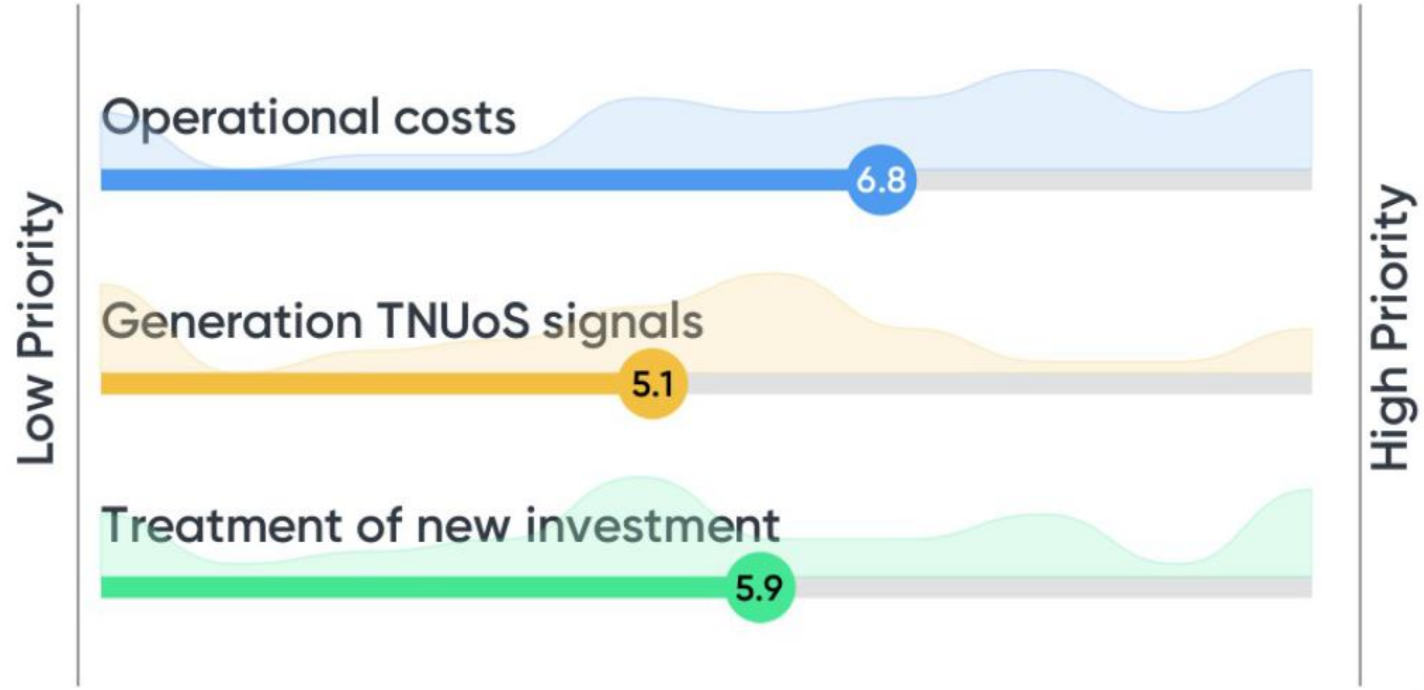
RIIO2

- Framework decision (late July 2018)
- Sector-specific methodology consultation (late 2018)
- Sector-specific methodology decision (mid-2019)
- Formal business plan submission (late 2019)
- Final determination (late 2020)
- RIIO2 starts

Charging Futures

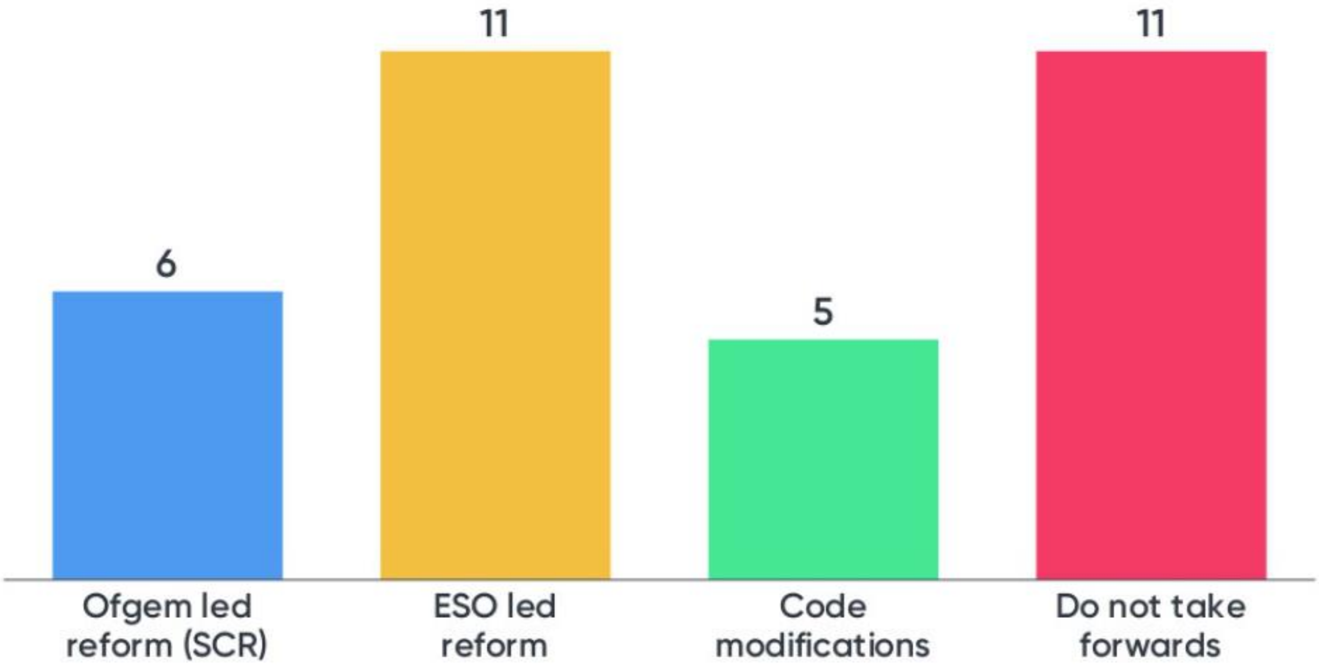
Feedback on reform to BSUoS

Priority of remaining elements



How should operational costs be taken forwards?

Mentimeter



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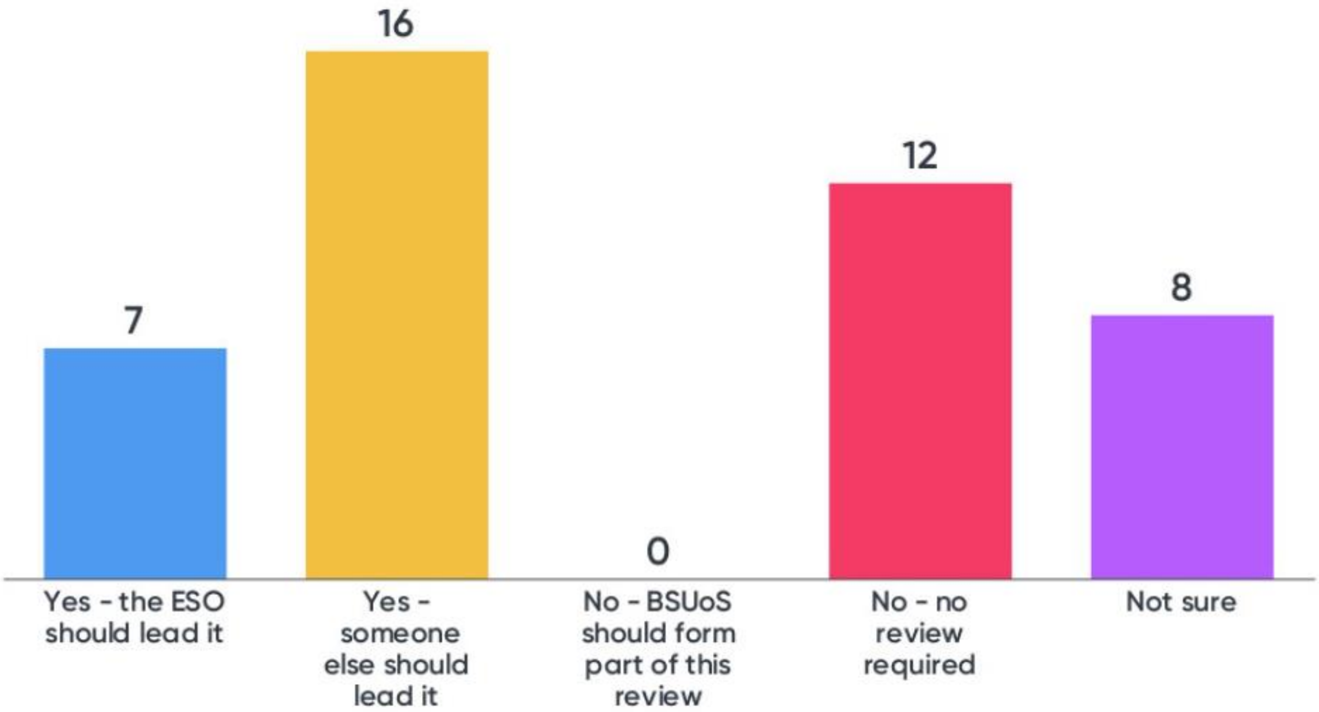
Do you consider that a Task Force should be launched to review BSUoS?

Mentimeter



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ESO role in charging reform

Rob Marshall, National Grid ESO

Our role

- Facilitate industry debate
  - Highlight where arrangements need to be reformed
  - Where appropriate, lead through change
  - Support Ofgem in the delivery of SCRs
- Use our voice to champion the consumer

Our goal

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Develop markets that create the right outcomes

- Enable market participants to make efficient business decisions
- Users are exposed to their cost and benefit to the whole system
- Deliver consumer value

Facilitate an open process

- All users have had the opportunity to contribute to the reform

ESO lead work

What could an ESO led package of work could look like?

ESO form a task force on a specific topic

- Propose options for change to industry
- Collaborate with taskforce members to remove and refine options
- Take forward preferred option into code modification(s)

Location of TCMF meetings

Rachel Tullis, National Grid ESO

AOB

Rachel Tullis, National Grid ESO

nationalgrid

Next meetings

October	November
No meeting in October	14
	Wednesday

Will be an 10:30am start unless otherwise notified.

We value your feedback and comments

If you have any ***questions*** or would like to give us ***feedback*** or share ***ideas***, please email us at:

cusc.team@nationalgrid.com

Also, from time to time, we may ask you to participate in surveys to help us to improve our forum – *please look out for these requests*

Close