SR Introduction to the Electricity Network: Charging & Regulation CPD Seminar

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Scottish & Southern Electricity Networks

CPD CERTIFIED
The CPD Certification Service
Collective Mark

Welcome

Michael Rieley
Scottish Renewables

Chair

Dr Simon Gill

University of Strathclyde

From BETTA to EMR

Charging for electricity networks

A Scottish Renewables CPD event

Simon Gill, University of Strathclyde

30th August 2017

simon.gill@strath.ac.uk

Currently seconded to…

The Scottish Government

https://upload.wikimedia.org/wikipedia/commons/3/33/Illustrations_to_Robert_Blair%27s_The_Grave_%2C_object_9_The_Soul_Hovering_over_the_Body.jpg

We all want a Secure Affordable and Sustainable energy system

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Why charge for networks?

The theory of it all

Trends in Charging

Introducing the cast: TNUoS to CDCM

The future

Regulated Natural Monopolies

Is this Sensible?

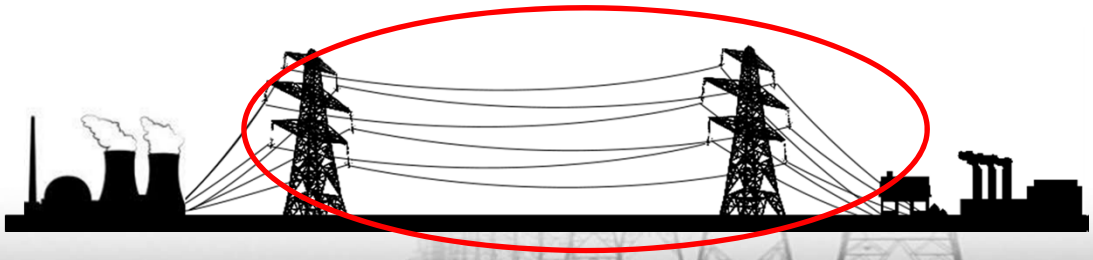
Huge fixed costs up capital investment
+
Low marginal operating costs
=
Natural Monopoly

but

Full Monopoly = Complete Market Power

so

Networks are *Regulated* Natural Monopoly



https://www.nap.edu/read/14670/chapter/3#29

What have networks done for us?

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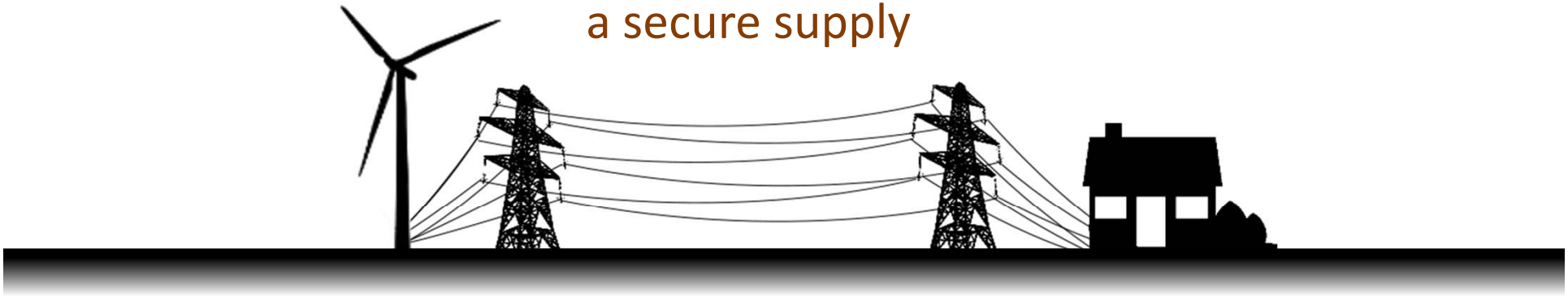
For **generators**: networks bring **reliable access to a market**

For **consumers**: networks facilitate competition and provide a secure supply

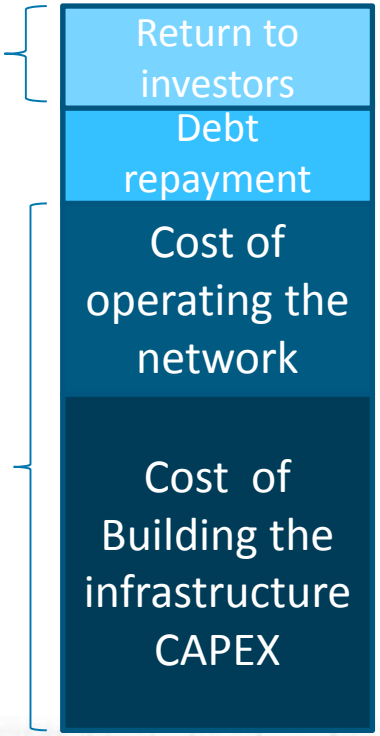


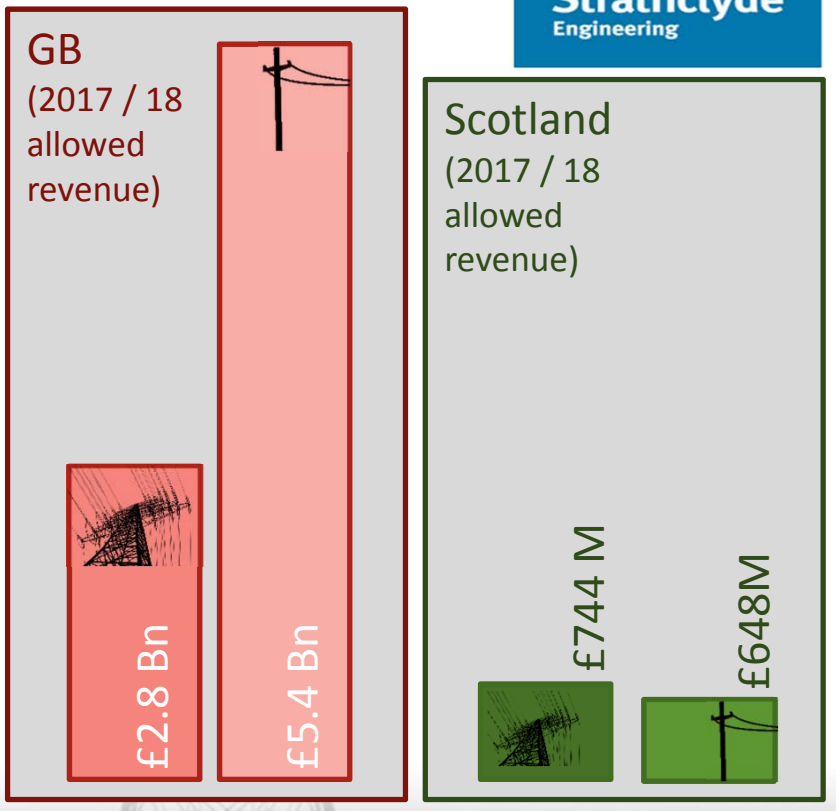
What is the value of the wind turbine to the household?
What is the value of the household to the wind turbine operator?

How much do they cost?

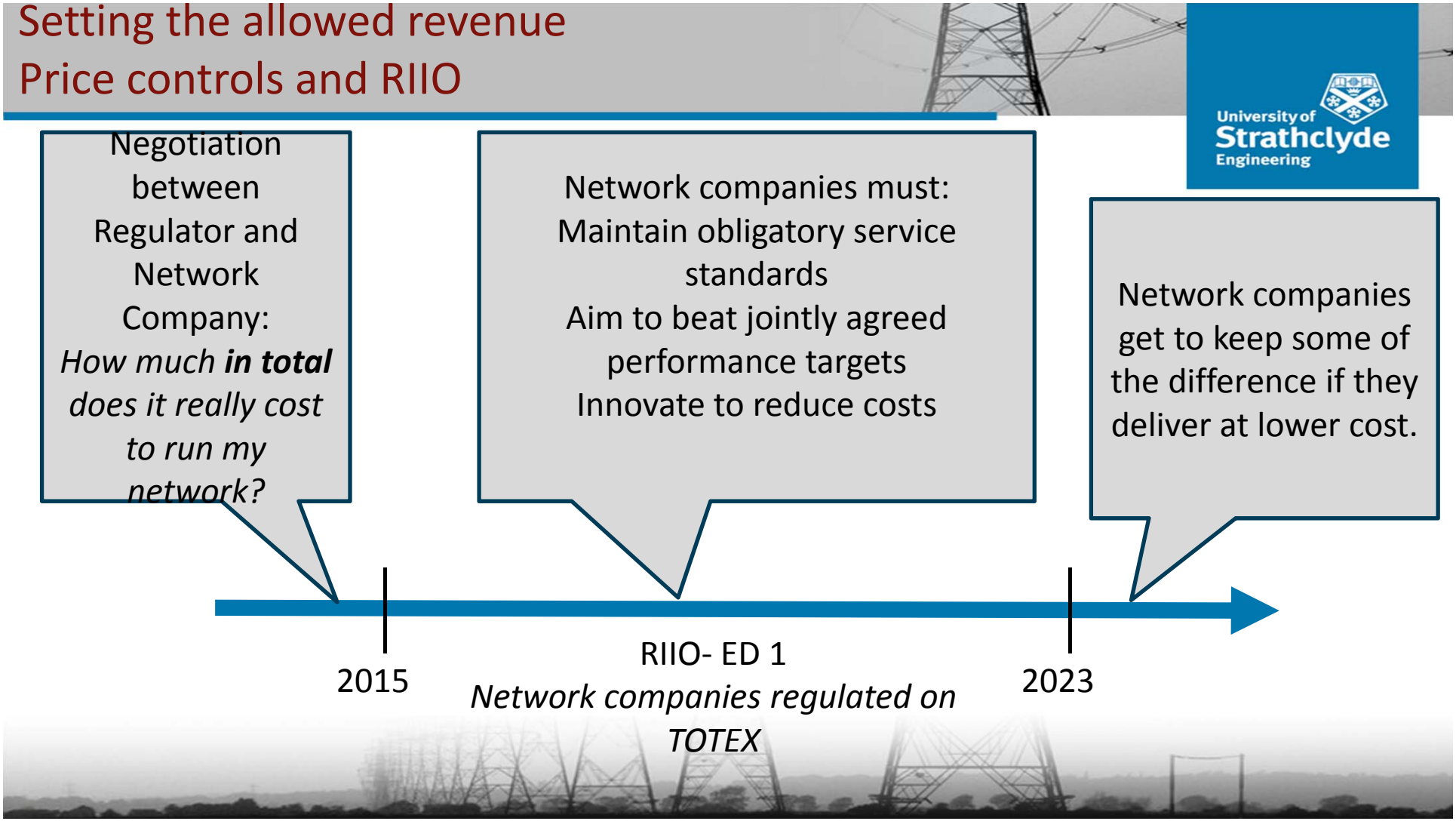
Only investors know how much return is required

Only the network companies themselves really know how much it costs to build and operate the network





Setting the allowed revenue
Price controls and RIIO



What drives network cost?

Energy Drawn from the grid in 1 year:
1,600 kWh
(Export: 1,500kWh)

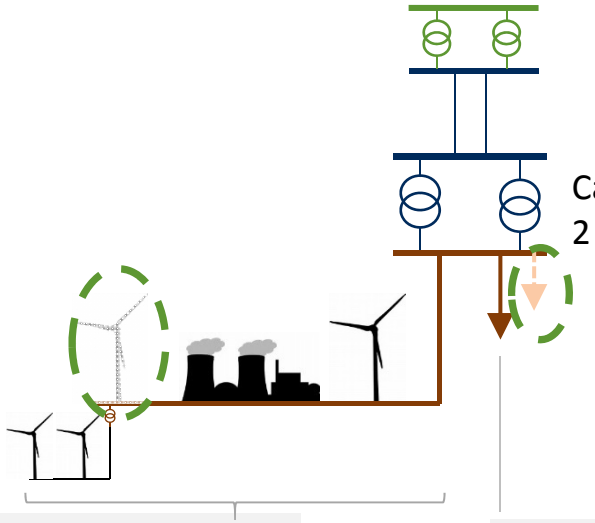
Demand at Peak: 3.7kW

Question:
Which house drives the largest grid costs?

Energy Drawn from the grid in 1 year:
3,100 kWh
(Export: 0kWh)

Demand at Peak: 3.7kW

What drives network cost?



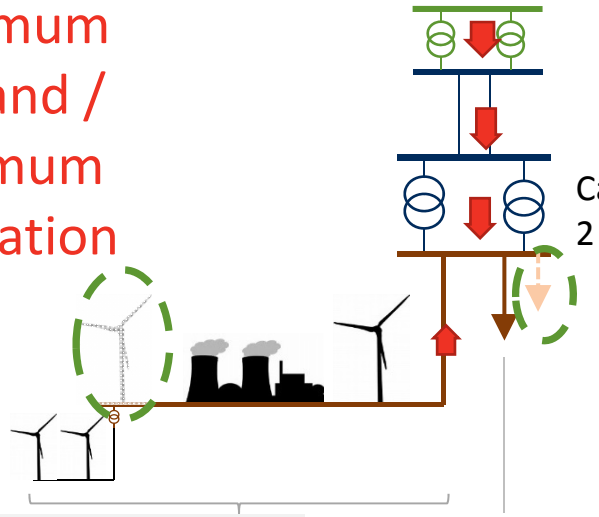
Capacity of transformer:
2 x 10MVA*

Simultaneous generation output:
Max : 12 MW
Min : 2MW

Existing Demand range:
2MW - 9MW

What drives network cost?

Maximum demand / minimum generation



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What drives network cost?

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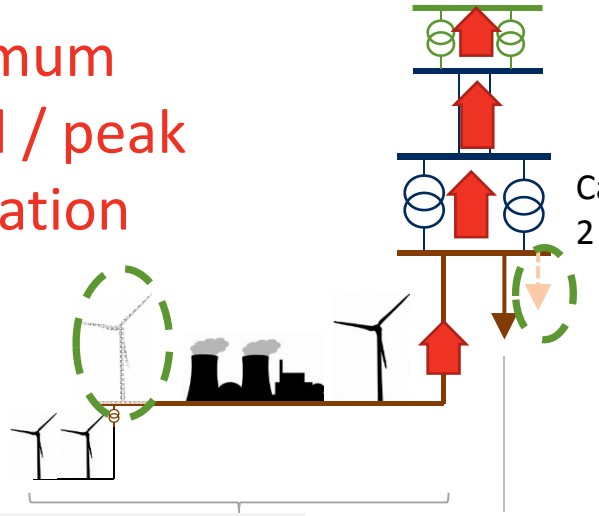
Minimum demand / peak generation



Capacity of transformer:
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Simultaneous generation output:
Max : 12 MW
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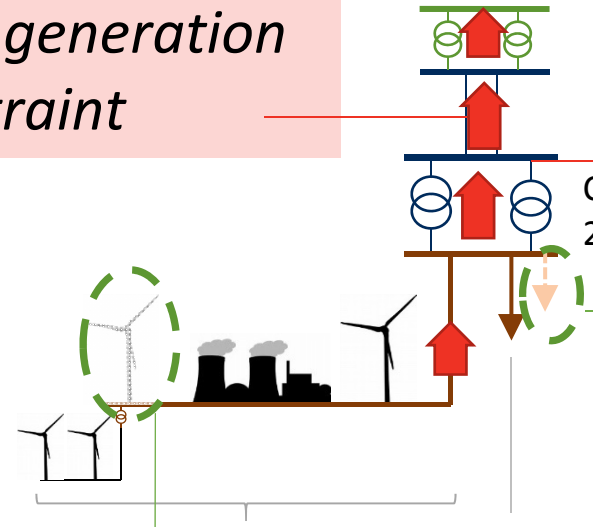
Existing Demand range:
2MW - 9MW

What drives network cost?

peak generation constraint



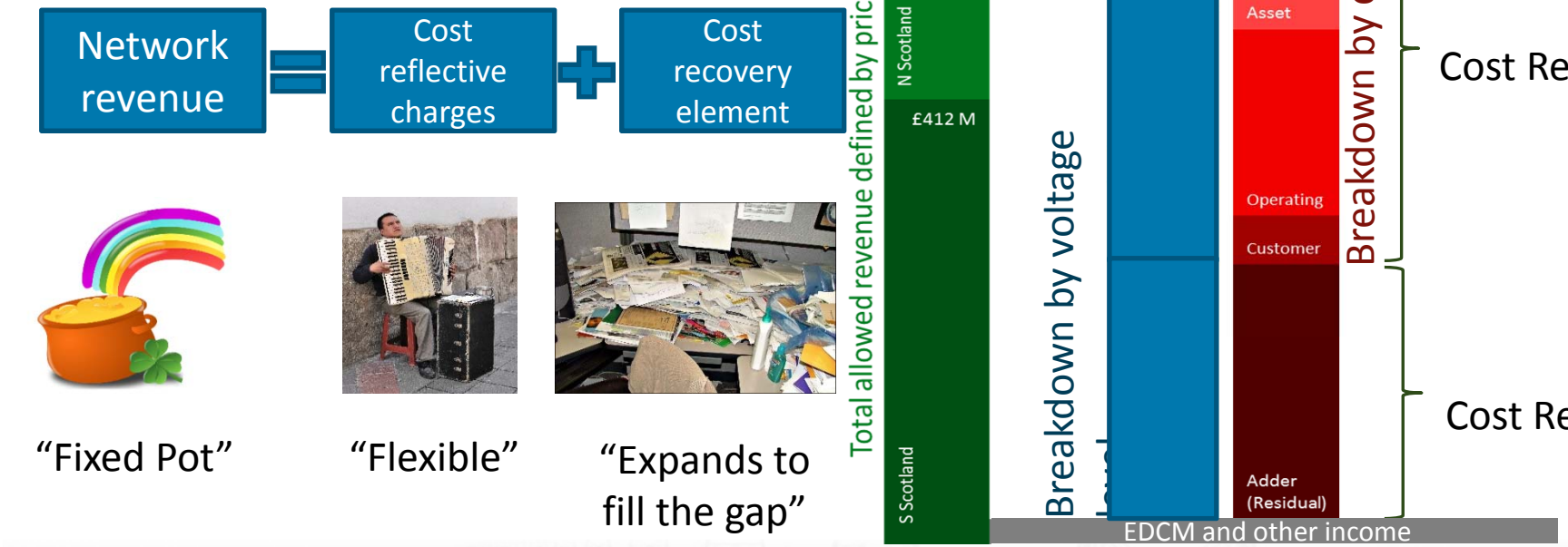
N-1 security firm capacity : *12 MW*

Capacity of transformer:
2 x 10MVA*

Possible new demand:
Reduces the need for network upgrades

Possible new generation:
Increase the need for network upgrades

Cost reflectivity and cost Recovery



https://en.wikipedia.org/wiki/Accordion
https://www.flickr.com/photos/denverjeffrey/1950409800

Connection Charges vs Use of System Charges

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Transmission

Connection charges are shallow

Only pay for your own assets up front

The rest is paid for through TNUoS year-by-year

But

For local part of the transmission network – you still pay for the upgrade

Distribution

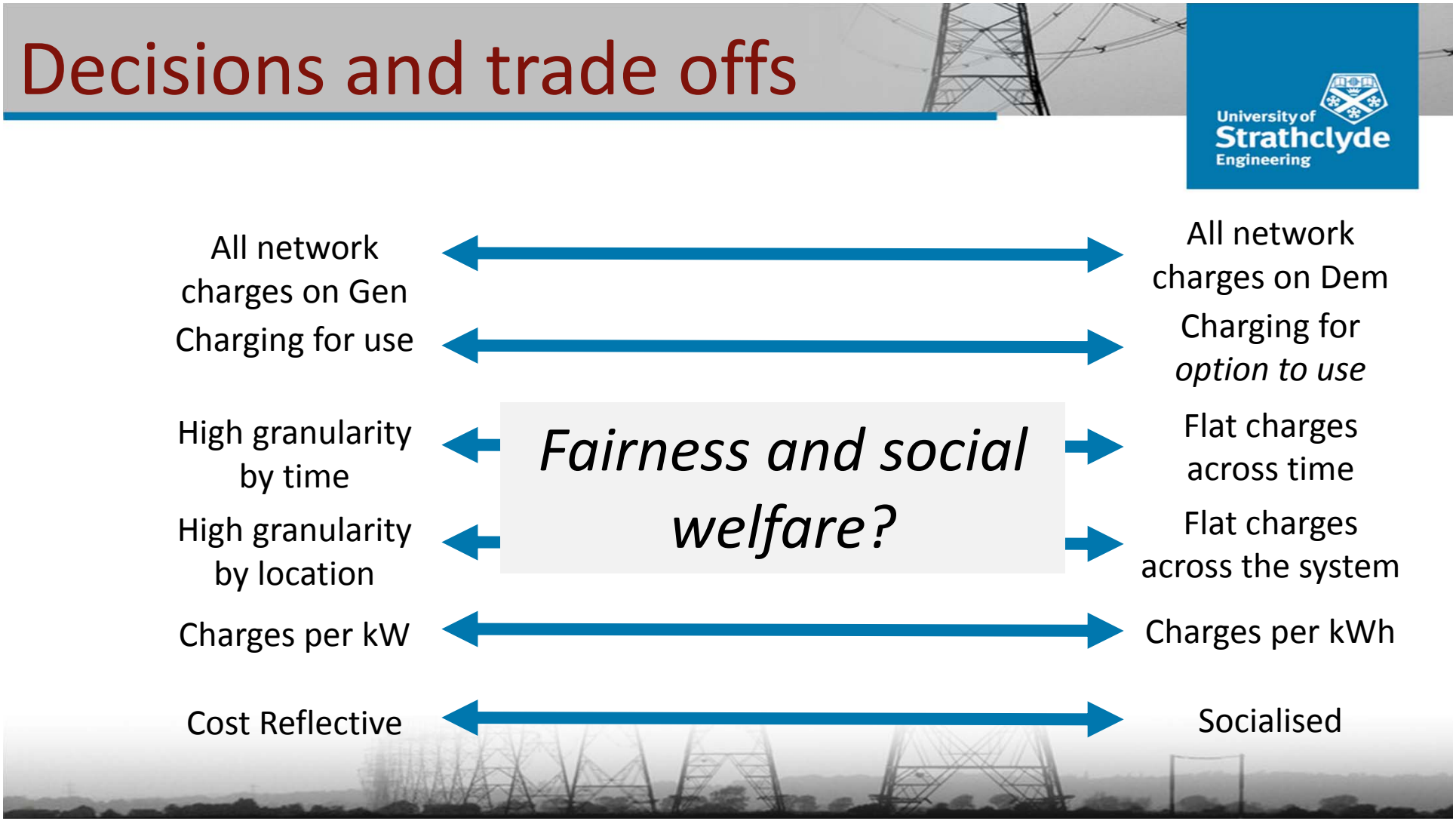
Connection charges are deeper

Sometime called 'shallow-ish'

Pay for 'sole use assets'

And contribute to extension assets up to 1 voltage level above your point of connection

Decisions and trade offs



The Cast

(From a generators perspective)

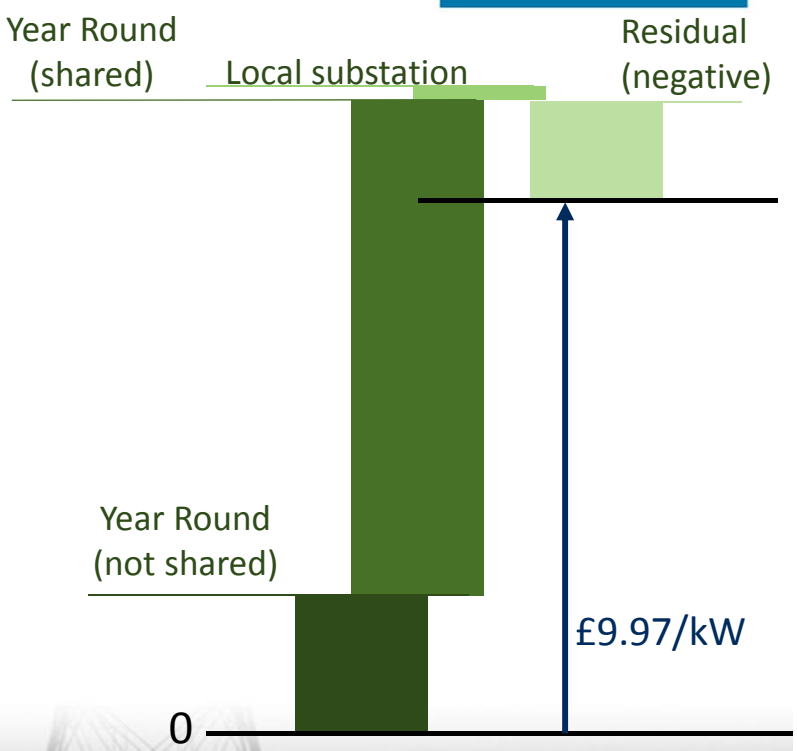
https://commons.wikimedia.org/wiki/File:Curtain_Call_of_Crossing_the_Ocean,_Legacy_20140712.jpg

Charges

Paid by:	
Pays for:	
Components of charge:	
Charged on:	
Cost reflective:	
Cost recovery:	

Generation TNUoS

Paid by:	Transmission connected generators
Pays for:	All transmission related costs
Components of charge:	Peak demand charge Year round charge Residual 'charge'
Charged on:	Peak demand = Transmission Entry Capacity (TEC) Year Round Charge = mix between TEC and Roughly proportional to 'kWh' charge Residual = TEC
Cost reflective:	Peak demand and year round designed to reflect contribution of user to network flows.
Cost recovery:	Residual supports cost recovery, but now wrapped up with other things (e.g. EU limit on network charges to generators) so about to go negative



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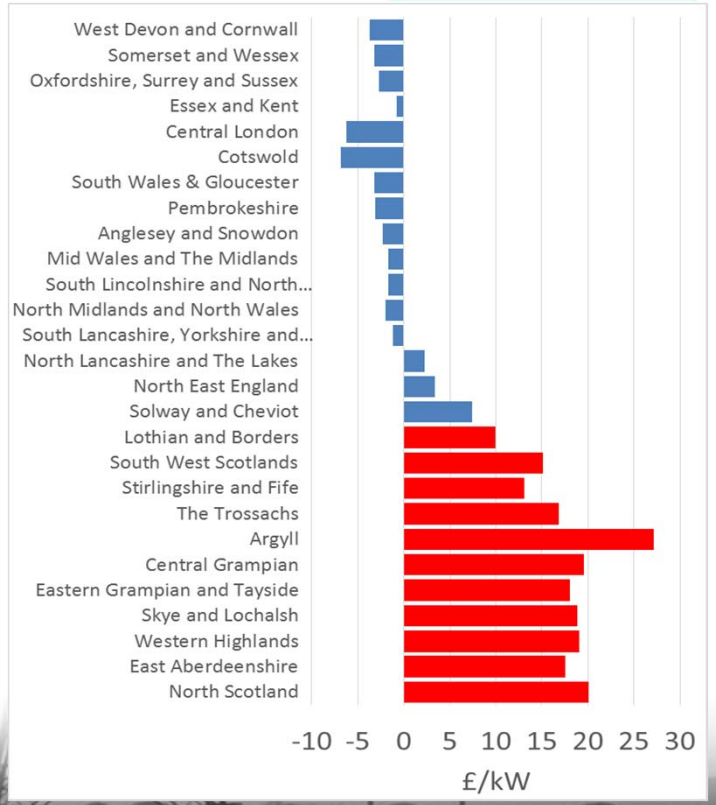

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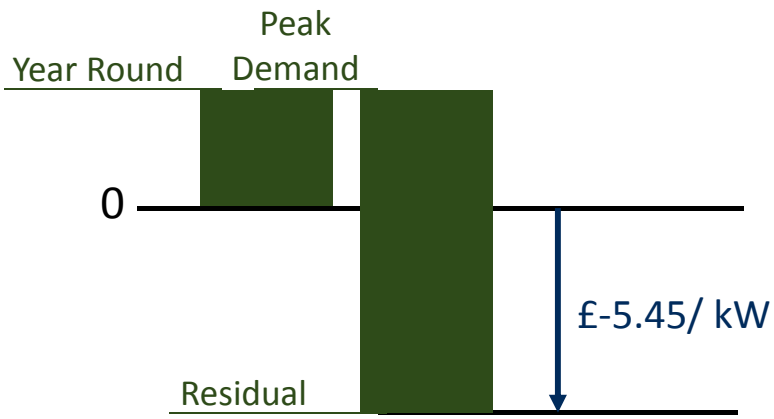
Small Generator Discount

Reduction for 132kV connected generators less than 100 MW capacity in Scotland.

Paid for by flat additional charge on demand TNUoS

Inverse of demand TNUoS

Paid by:	Distribution connected generators via their off-taker
Pays for:	All transmission related costs
Components of charge:	Peak demand charge Year round charge Residual 'charge'
Charged on:	Peak demand = TRIAD output Year Round Charge = TRIAD output Residual = TRIAD output
Cost reflective:	Peak demand and year round designed to reflect contribution of demand to network flows… generators give *negative demand* so equal and opposite contribution
Cost recovery:	Demand residual designed to recover allowed revenue from demand. Generators give *negative demand* so are paid the residual – actively works against cost-recovery



Inverse of demand TNUoS

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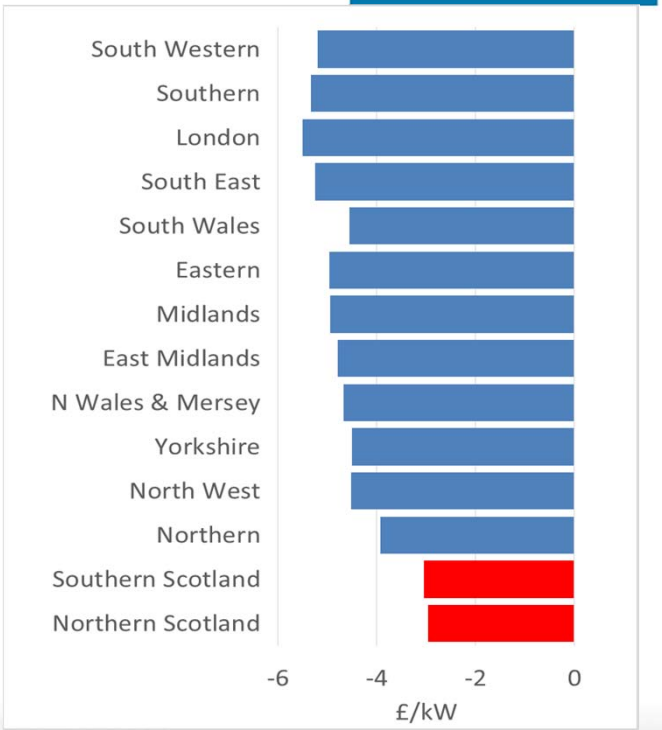
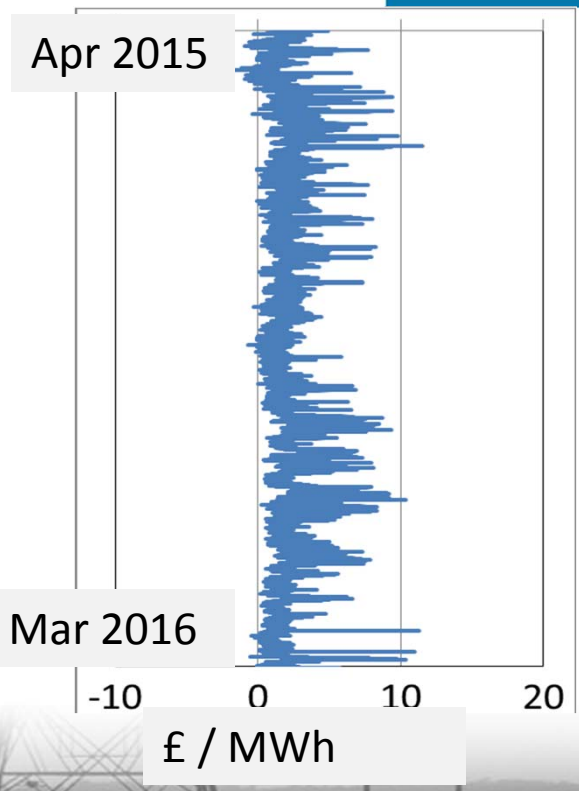


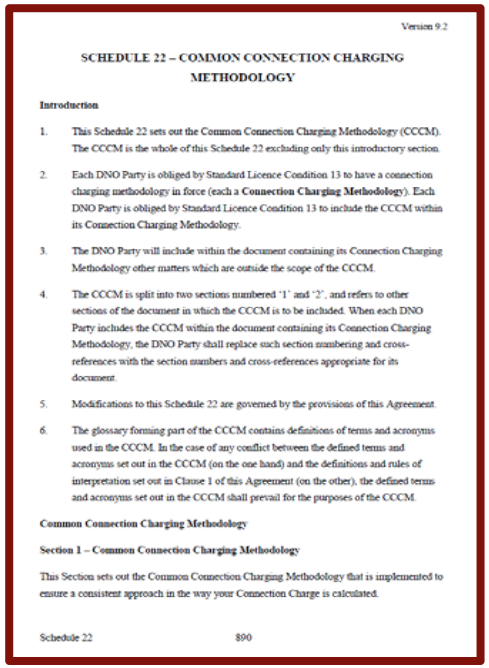
Balancing Use of System Charges (BSUoS)

Paid by:	All transmission connected generators and suppliers
Pays for:	Costs of balancing the system
Components of charge:	Fixed £ / MWh figure for every half hour.
Charged on:	MWh generated or drawn from the system in that half hour.
Cost reflective:	Attempts to assign balancing costs to the half hour they were incurred
Cost recovery:	But flat charges mean costs socialised across all users in each half hour in proportion to units.



Common Connection Charging Methodology (CCCM)

Paid by:	New connections to the distribution network
Pays for:	Sole use assets and contribution to network reinforcement up to 1 voltage level above the point of connection
Components of charge:	Sole use assets = 100% funded by generator Reinforcement = split between generator and DNO (i.e. passed on through UoS)
Charged on:	Sole use: Cost of equipment and work plus small Reinforcement: minimum acceptable scheme
Cost reflective:	Generator pays what it costs for sole use 1 generator can pay reinforcement contribution that can then be used by others
Cost recovery:	Via DUoS



Version 9.2

SCHEDULE 22 – COMMON CONNECTION CHARGING METHODOLOGY

Introduction

1. This Schedule 22 sets out the Common Connection Charging Methodology (CCCM). The CCCM is the whole of this Schedule 22 excluding only this introductory section.
2. Each DNO Party is obliged by Standard Licence Condition 13 to have a connection charging methodology in force (each a **Connection Charging Methodology**). Each DNO Party is obliged by Standard Licence Condition 13 to include the CCCM within its Connection Charging Methodology.
3. The DNO Party will include within the document containing its Connection Charging Methodology other matters which are outside the scope of the CCCM.
4. The CCCM is split into two sections numbered '1' and '2', and refers to other sections of the document in which the CCCM is to be included. When each DNO Party includes the CCCM within the document containing its Connection Charging Methodology, the DNO Party shall replace such section numbering and cross-references with the section numbers and cross-references appropriate for its document.
5. Modifications to this Schedule 22 are governed by the provisions of this Agreement.
6. The glossary forming part of the CCCM contains definitions of terms and acronyms used in the CCCM. In the case of any conflict between the defined terms and acronyms set out in the CCCM (on the one hand) and the definitions and rules of interpretation set out in Clause 1 of this Agreement (on the other), the defined terms and acronyms set out in the CCCM shall prevail for the purposes of the CCCM.

Common Connection Charging Methodology

Section 1 – Common Connection Charging Methodology

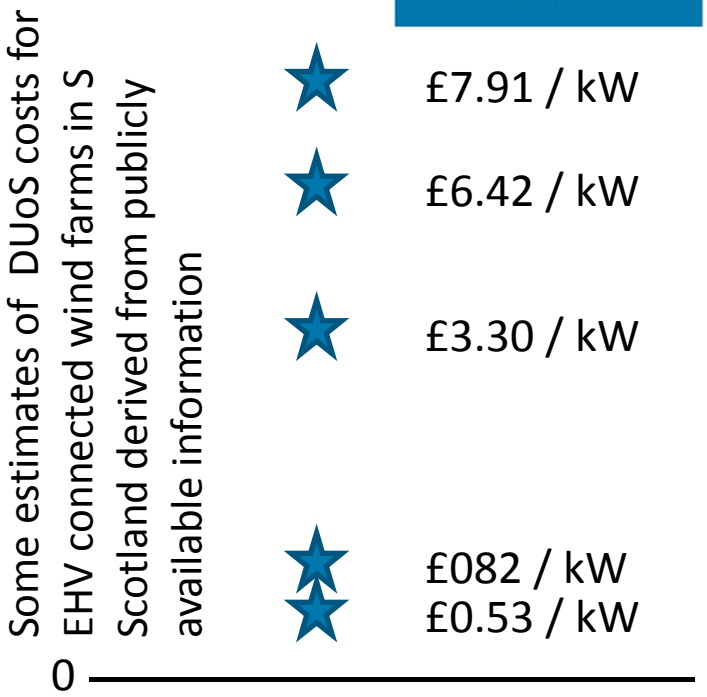
This Section sets out the Common Connection Charging Methodology that is implemented to ensure a consistent approach in the way your Connection Charge is calculated.

Schedule 22 890

https://www.dcusa.co.uk/DCUSA%20Document%20Public%20Version/DCUSA%20Schedule%2022%20v9.2.pdf

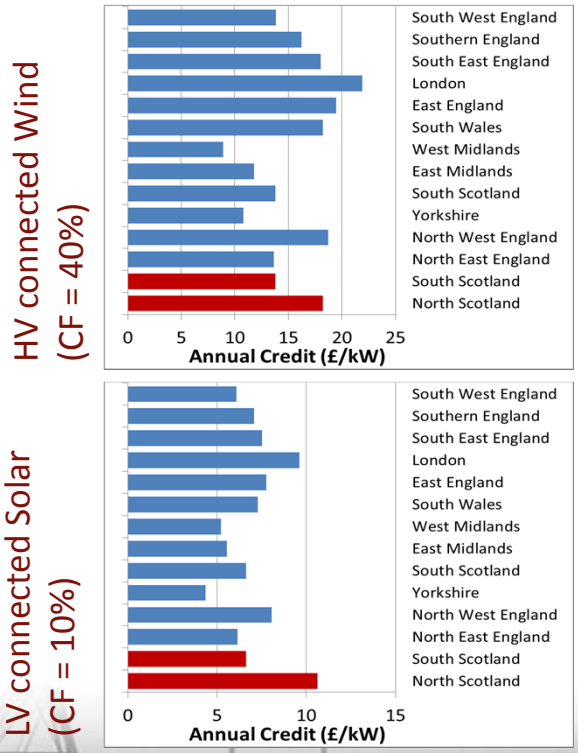
EHV Common Distribution Charging Methodology (EDCM)

Paid by:	**All EHV connected customers** (in Scotland connections at 33kV and to the 11kV bus bar of a primary substation)
Pays for:	Forward looking costs associated with the EHV distribution network
Components of charge:	Fixed charge per day Fixed charge per kw (kVA) Winter week day peak 'super-red' per kWh credit
Charged on:	Fixed Charge per day: Site specific analysis of impact on distribution network Super-red credits to non-intermittent generators when capable of supporting network at peak
Cost reflective:	In theory "highly": site specific analysis used to identify contribution of each induvial customer to future network requirements
Cost recovery:	Residual charges fully recovered from demand-only customers



Common Distribution Charging Methodology (CDCM)

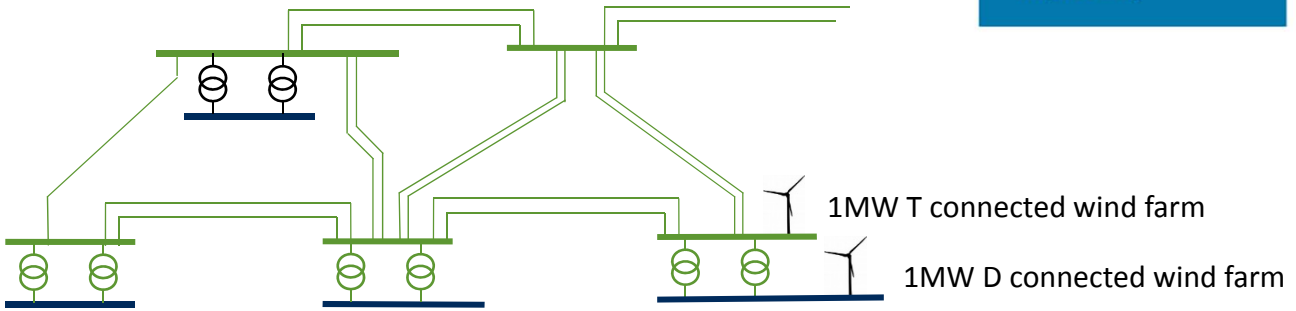
Paid by:	All LV (400v) and HV (6.6, 11kV) connected customers
Pays for:	Forward looking costs associated with the whole distribution network
Components of charge:	Intermittent: flat rate kWh 'credit' Non-intermittent: Banded rate kWh 'credit' Small fixed charge per meter for HV
Charged on:	Almost entirely kWh output – always a credit
Cost reflective:	Assumption that DG reduces need for network upgrade… credit rewards this Averaged over whole Distribution Area Generators Charged (or credited) based on impact *at their own voltage level and above only)*
Cost recovery:	Residual charges fully recovered from demand-only customers



Embedded Benefits

Elements of charging that can lead to Embedded benefits:

- TNUoS
- BSUoS
- Losses



Question: what is the difference in impact on the transmission network of the D connected wind farm compared with the T connected wind farm?

Answer: *only one thing … different flows on the transformers!*

Embedded Benefits: Example: TNUoS

Transmission Generation TNUoS

NG Levies generation TNUoS directly on generator

National Grid → Generator

Generator pays NG directly and specifically for TNUoS

Supplier wraps all costs up into tariffs for demand customers including TNUoS contribution

TNUoS for distributed Generation

NG Levies demand TNUoS directly on supplier net peak demand 'TRIAD'

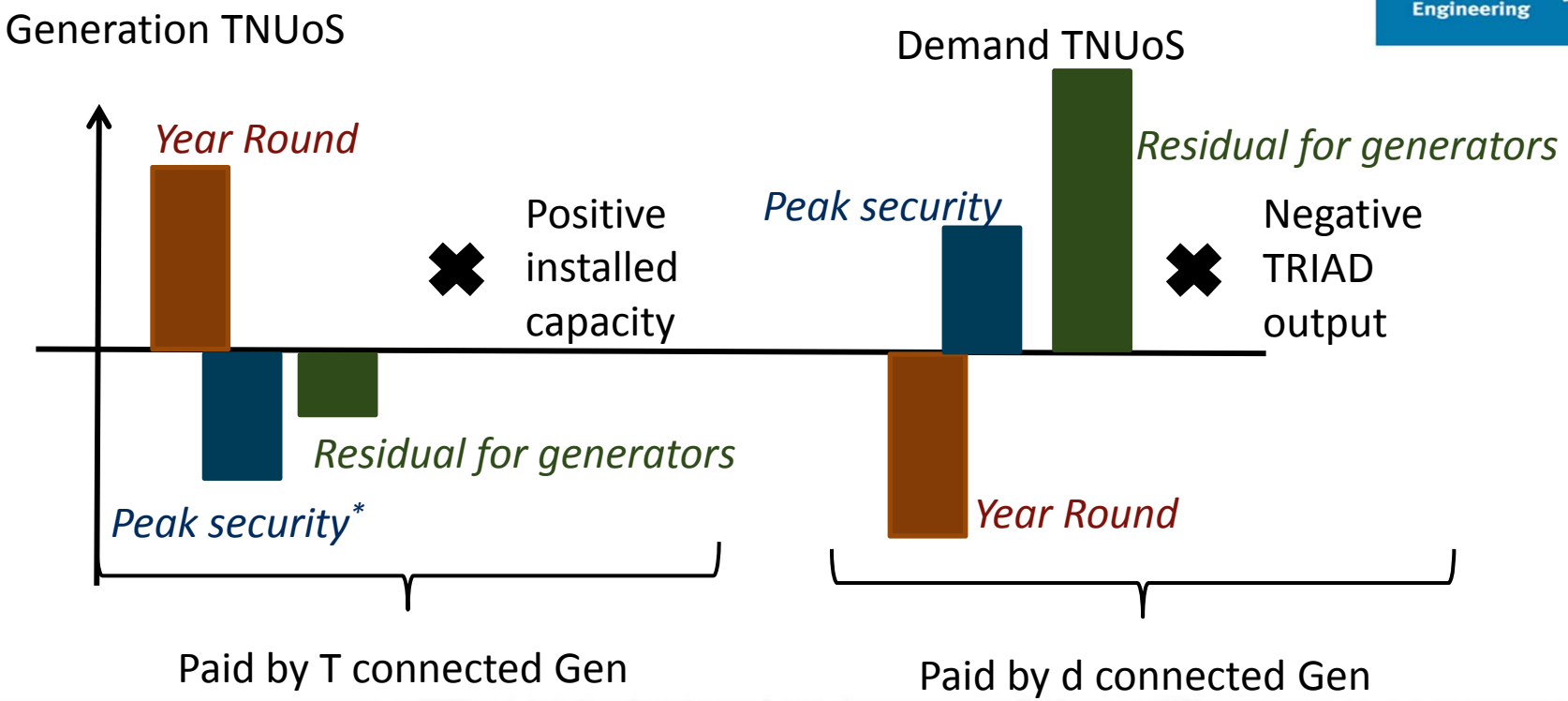
National Grid → Supply company

Supplier pays NG specifically for TNUoS
(but a bit less than it would have done without DG to offset some peak demand)

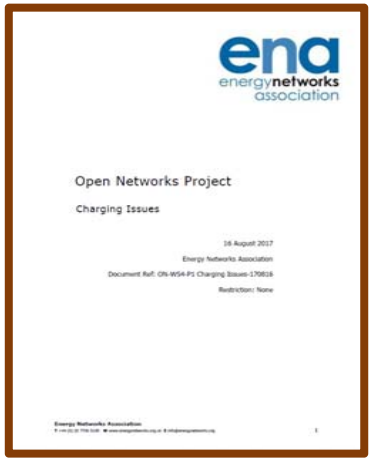
Supplier acts as off-taker for Distributed Generator

DG agrees PPA rate with supplier which included benefit from reduction of suppliers TNUoS benefit

Embedded Benefits: Illustration of why



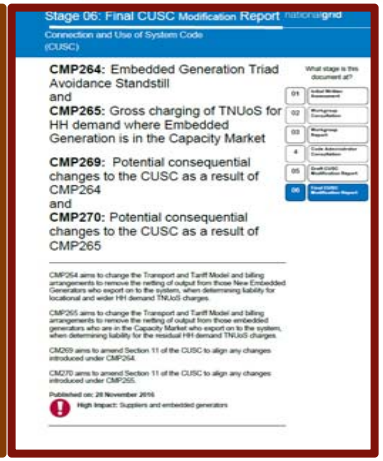
The Future


ena
energynetworks
association
Open Networks Project
Charging Issues


HM Government
ofgem
Upgrading Our
Energy System
Smart Systems
and Flexibility Plan
July 2017


Distribution Charging Methodology Review – Stage Two
Report
July 2017


ofgem

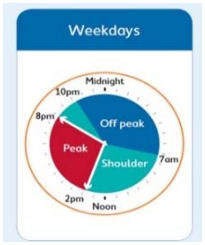

Stage 06: Final CUSC Modification Report
Connection and Use of System Code
(CUSC)
CMP264: Embedded Generation Triad Avoidance Standstill
and
CMP265: Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market
CMP269: Potential consequential changes to the CUSC as a result of CMP264
and
CMP270: Potential consequential changes to the CUSC as a result of CMP265

The Future

Smart Consumer

Flexibility (Storage, Generator, Demand)

Smart Meters



~~*Dumb*~~ *Shrewd* *Tariffs*

- Canny network customers will respond to whatever incentives exist
- Incentives based on assumptions of dumb consumers will drive bad behaviour
- Need tariffs that really do reward what the 'system' needs

https://pixabay.com/en/smart-home-home-technology-2005993/

Conclusion: Cost reflective? Fair?
Annual Use of System charges for a wind farm…

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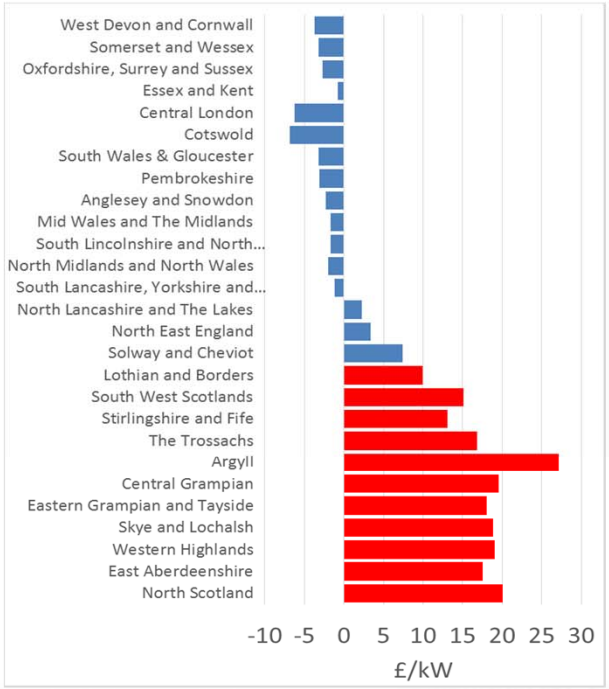
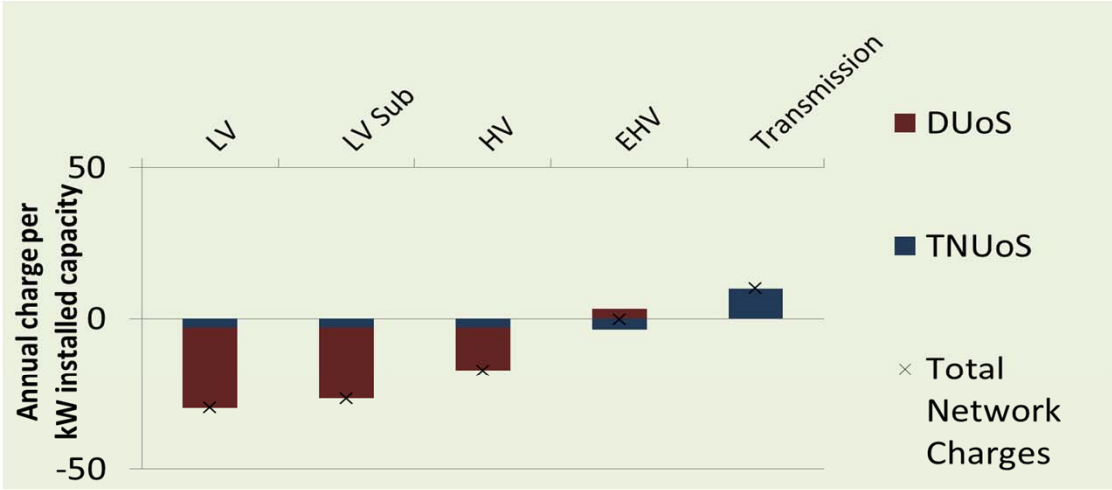
Variation by region of GB for transmission connection



Variation by voltage level in S Scotland



Thanks!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www.linkedin.com/in/simon-gill-energy/

Q & A

Transmission Network Charging

Rob Marshall
National Grid

nationalgrid

Transmission Network Charging

Rob Marshall

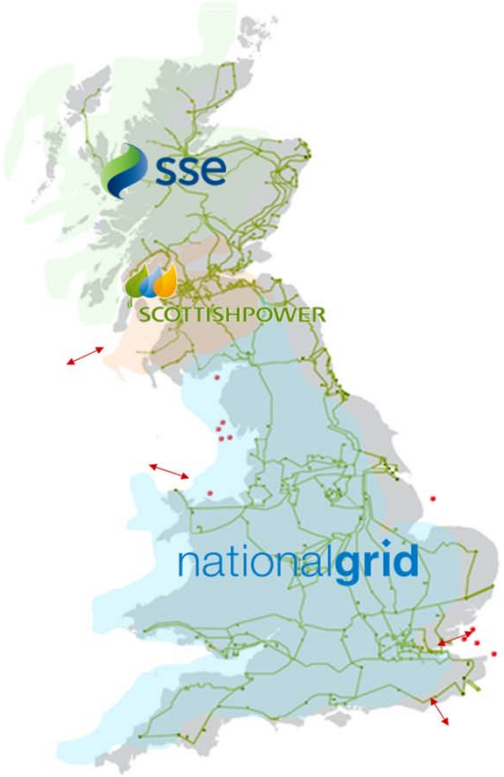
Transmission Network Charging

nationalgrid

- Who are transmission networks?
- How do transmission charges work?
- How do transmission charges change?
- What is changing right now?
- How do I keep up to date with changes?

GB Electricity Transmission

nationalgrid



Multiple **TO**s

One **SO**

Independent Regulator

SHET

SPT

NGET

Interconnectors/ OFTOs*

National Electricity **Transmission System Operator**

National Grid Electricity Transmission

ofgem

Regulates price controls and charging methodologies

Transmission Owner

Transmission Use of System Charge (TNUoS)

£2.7bn

- Recovers the cost of all shared assets
- Tariffs include locational and non-locational elements
- Tariffs are set annually, in advance
- Charges split between G(16.7%) D(83.3%) – 2016/17
- Generation tariffs are capped by a c2.50/MWh limit set by the EU
- Generations charges are charged against transmission entry capacity (TEC)
- Demand charges charged based on usage:
  - HH – Triad demand
  - NHH – Annual usage between 16:00 & 19:00

Connection Charges

£210m

- Recovers the cost of single user assets
- Charges are set directly from the cost of single user assets built for customers' connections

System Operator

nationalgrid

Balancing Services Use of System Charge (BSUoS)

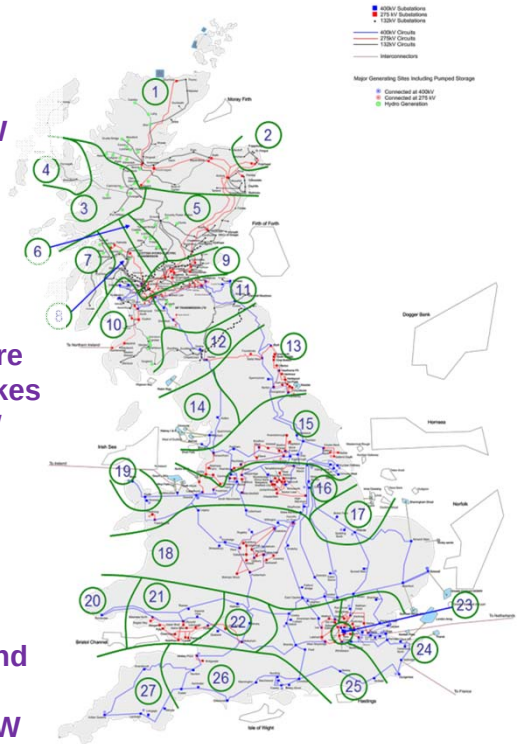
~£1bn

- Recovers the cost of operating the system
- Tariffs are non-locational
- Charges are split between G(50%) D(50%)
- Tariffs are calculated and invoiced ex post
- Charges are based on MWh usage in each half hourly period

Locational TNUoS Tariffs

nationalgrid

Generation Charges (Wider)



Zone 4:
Skye and Lochalsh
£11.19 /kW

Zone 1:
North Scotland
£16.29 /kW

Zone 14:
North Lancashire & The Lakes
£5.05 /kW

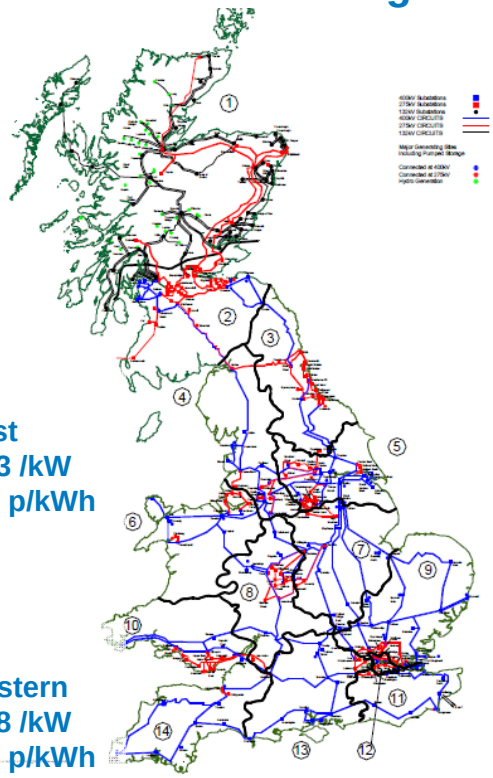
Zone 13:
North East England
£2.90 /kW

Zone 27:
West Devon and Cornwall
-£3.69 /kW

Zone 23:
Central London
-£5.97 /kW

Demand Charges

Final TNUoS tariffs for 2016/17



Zone 1:
Northern Scotland
HH: £40.97 /kW
NHH: 5.77 p/kWh

Zone 4:
North West
HH: £42.83 /kW
NHH: 5.69 p/kWh

Zone 9:
Eastern
HH: £46.54 /kW
NHH: 6.35 p/kWh

Zone 14:
South Western
HH: £48.58 /kW
NHH: 6.88 p/kWh

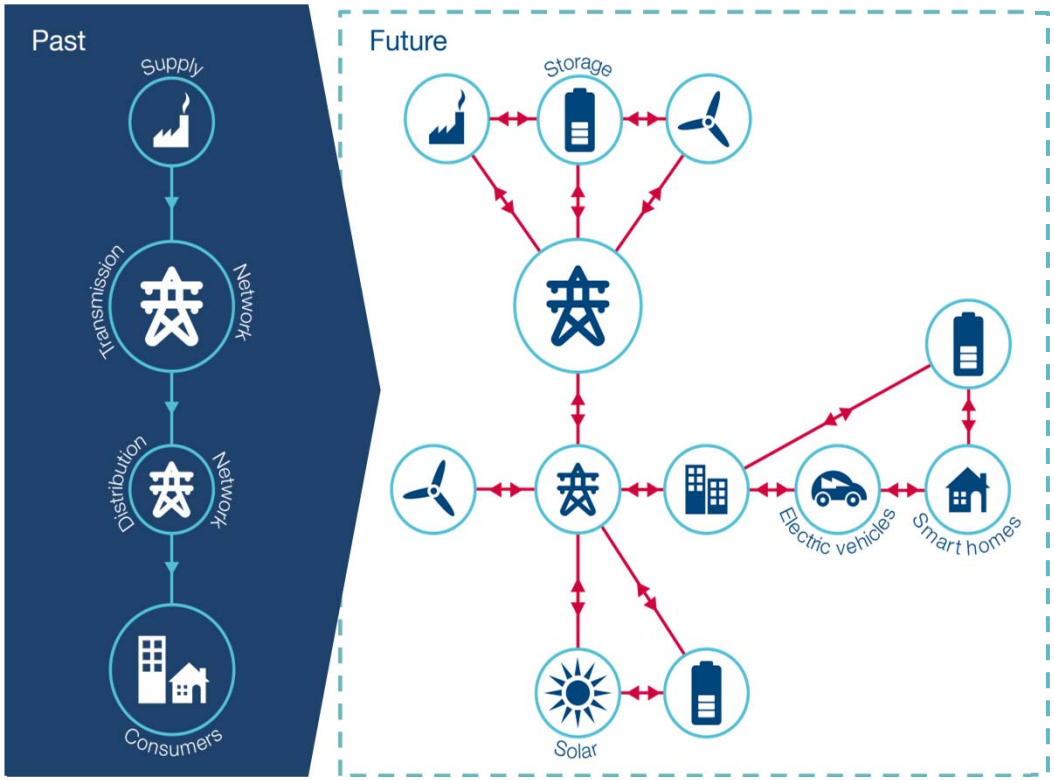
Zone 12:
London
HH: £51.87 /kW
NHH: 6.51 p/kWh

The Residual

Final TNUoS tariffs for 2016/17

- **The generation and demand residual** adjusts the wider charges to collect the remaining revenue not collected from **locational charges**
  - For Generation: this is very low due to the high level of locational element and a €2.50/MWh cap
  - For Demand: this is very high due to the low revenue recovery of the locational element

A changing system



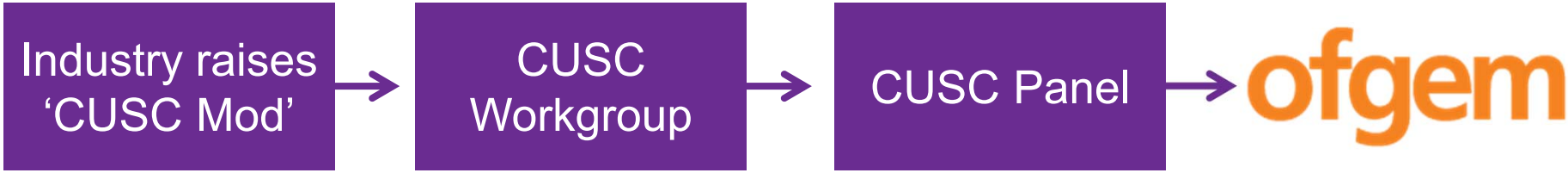
+ >10 GW Solar

- 15 GW Fossil Fuel

+ 10 GW Wind

Coal free day

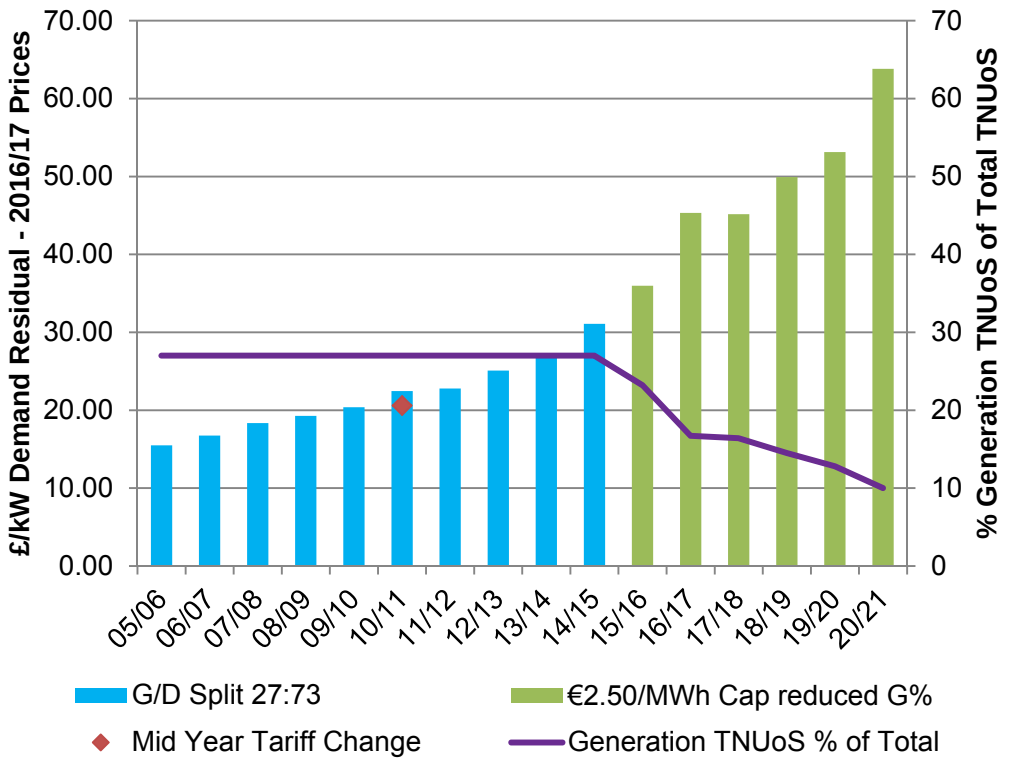
CUSC Modifications



CUSC Mods are assessed against the applicable CUSC objectives

- Facilitates competition
- Cost reflective
- Complies with transmission license
- Complies with the Electricity Regulation
- Promotes efficiency in implementation

CMP 264/265



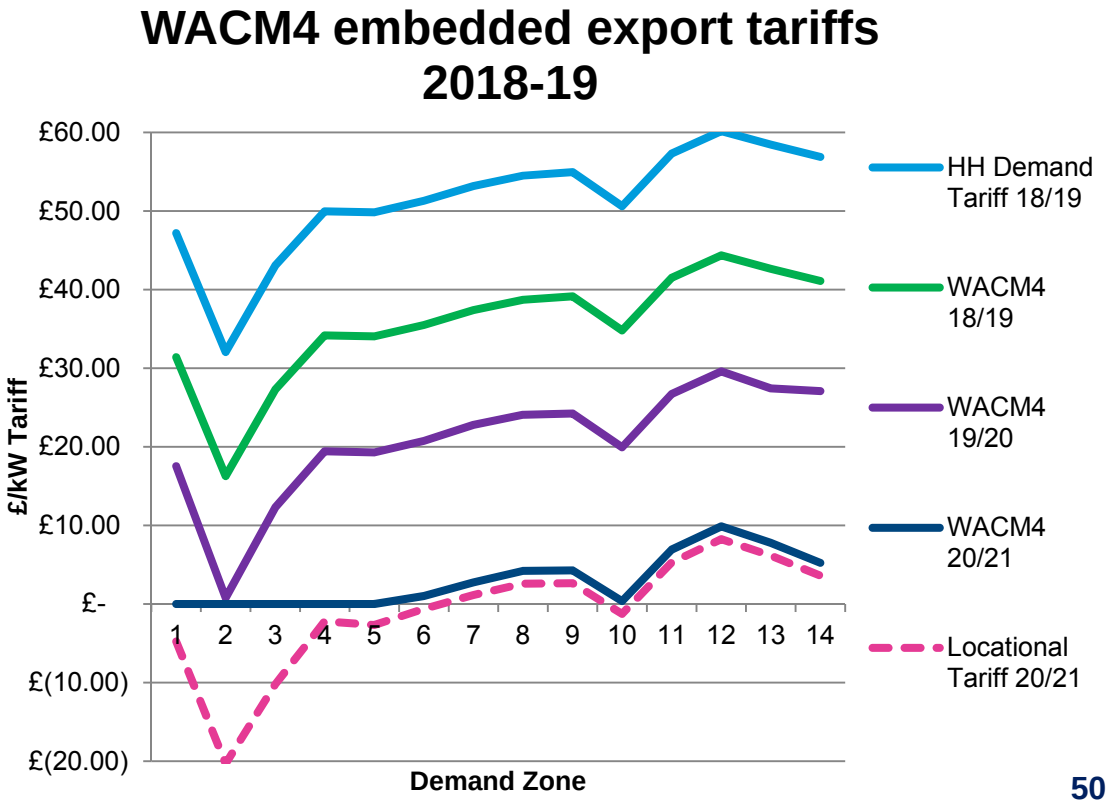
- Demand residual has increased significantly in recent years
  - Growth in revenue recovery
  - €2.50/MWh cap on generation TNUoS charges
  - Reducing demand base
- In May16 Scottish Power and EDF raised CMP 264&265
  - They looked to remove the demand residual for embedded generators
- The mods reported to Ofgem in November 2016
- Ofgem approved ‘WACM 4’ in June 2017

CMP 264/265 WACM4

nationalgrid

Workgroup Alternative CUSC Modification 4

- Uses the locational element of the demand tariff as its basis
- Adds the value of avoiding reinforcement at GSP
  - Last estimated by National Grid as £1.62/kW in 2013/14 prices
- Floors any negative values at £0/kW



Targeted Charging Review

In August 2017 Ofgem announced the launch of a **Significant Code Review (SCR)** to deliver the **targeted charging review.**

The SCR will

- Consider residual network charges – both transmission and distribution
- Keep other 'embedded benefits' under review

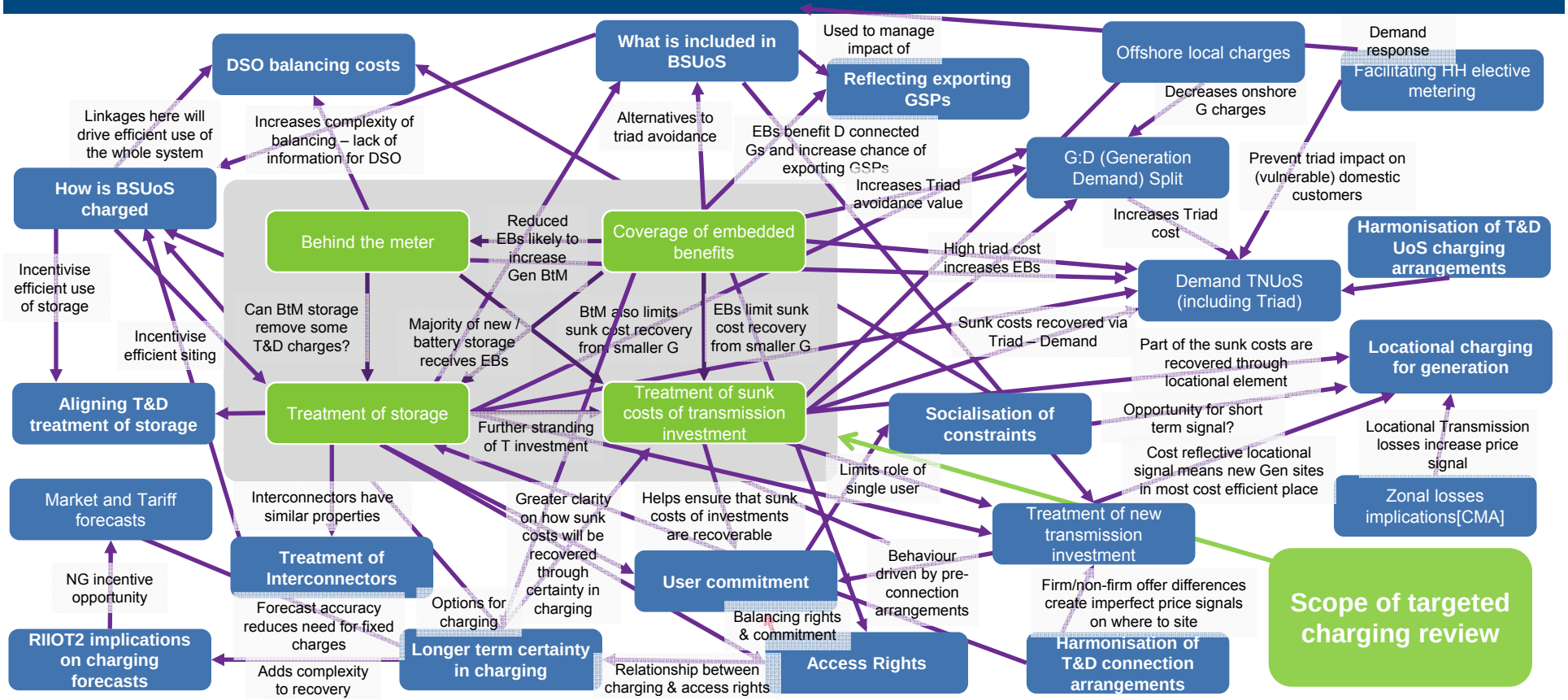
Timeline

- Q4 2017 Working paper published
- Q2 2018 Minded to decision and draft impact assessment
- Q3 2018 Final decision and final impact assessment
- April 2020 Changes come into effect

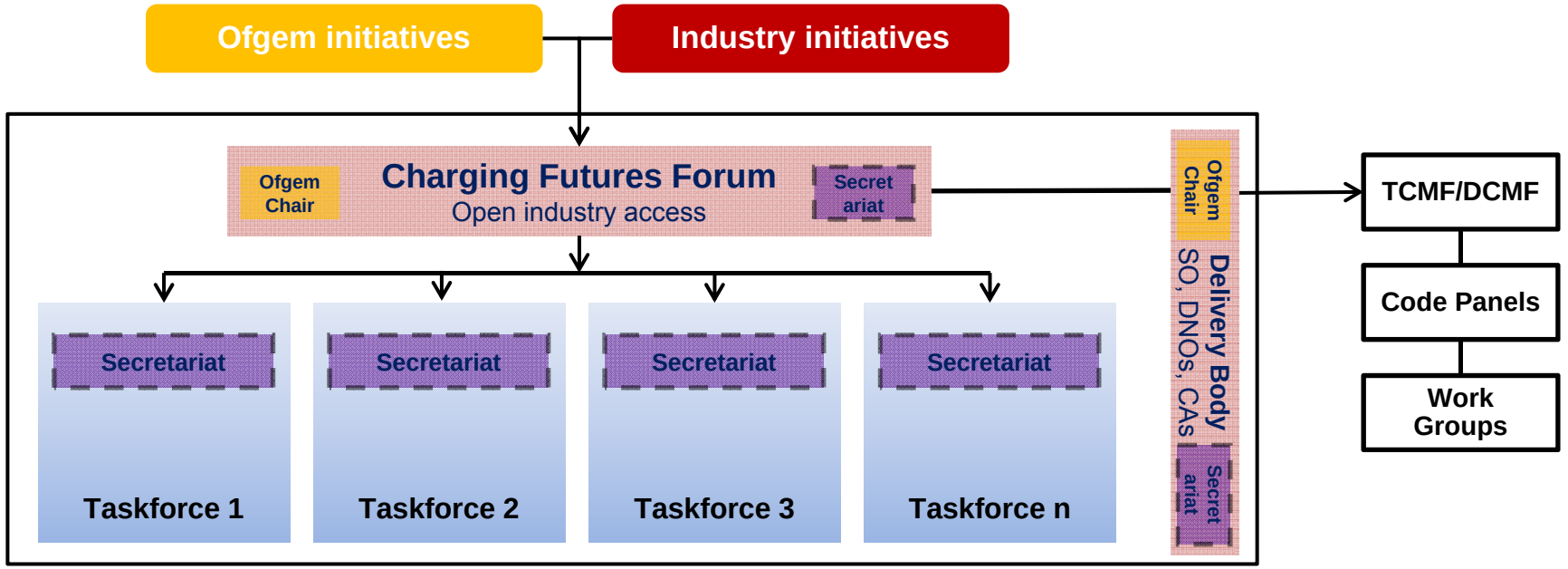
SCRs are a tool for Ofgem to deliver holistic and accelerated changes to industry codes

Scope modules of the targeted charging review

nationalgrid



Charging Futures



Sign up for attendance or to be kept up to date https://www.surveymonkey.co.uk/r/YJT996W

Alternatively, contact charging.futures@nationalgrid.com

Questions

Q & A

Networking Break

Distribution Network Charging

Paul McGimpsey

Scottish Power Energy Networks

SP ENERGY NETWORKS

SR Introduction to the Electricity Network: Charging & Regulation CPD Seminar

Paul McGimpsey
Distribution Network Charging
30 August 2017

Distribution Charging Reviews

- DNOs have a requirement under their licences to review the methodologies used for the calculation of DUoS charges on an annual basis and bring forward changes where appropriate.

- In the time since CDCM and EDCM were developed, the industry has undergone significant change, most notably in the increase of DG.

- It is anticipated that change will continue into the future and any changes proposed now should be able to adapt to future developments.

- The EDCM review made several recommendations one of which was the development of a single methodology to replace both CDCM and EDCM.

- The CDCM review has been wide reaching, considered changes to costing models, tariff structures, IDNO arrangements and a single combined methodology.

Distribution Charging Reviews - Initial Conclusions

- Two contrasting costing model options will be developed further. Essential these are flexible enough to take account of the ways in which the energy networks are evolving.

- A review of the tariff structures is necessary. Under review are proposals to recover a greater proportion of costs through fixed charges. Higher fixed charges would provide greater stability in tariffs year-on-year.

- Future products are being considered as part of the costing model impacts. An ancillary services approach has been considered where payment could be made for a variety of services such as DSR, which could defer reinforcement.

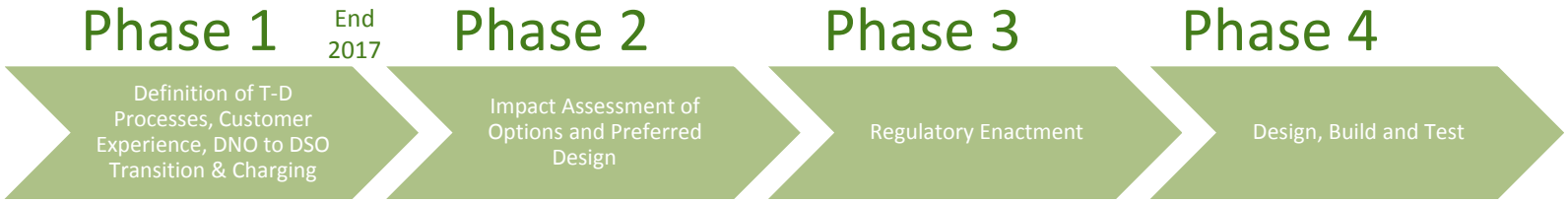
- Moving towards a single methodology (combining the CDCM and EDCM) across all voltage levels has significant support from the industry. This has the potential of simplifying the EDCM and making the resultant models more transparent.

The ENA Open Networks Project

1. A major new long-term project that will transform the way that local distribution networks and national transmission networks will operate.
2. It will lay the foundations of a smart energy grid in the UK.
3. It will enable the UK's energy networks to:
    - Address the challenges caused by the continued uptake of distributed generation.
    - Move from traditional role of simply delivering electricity, to one where they are a platform and enabler for a whole range of new smart energy technologies
4. Network operators must meet challenges whilst:
    - Continuing to deliver safe and secure operation of distribution networks.
    - Ensuring efficient and timely access to the network for customer.
    - Providing value for money.

The ENA Open Networks Project

- First Phase to deliver in 2017
- Expect Second Phase in 2018 and then beyond to RIIO ED2/T2 (2023)



Workstreams aligned with 2017 objectives:

1. Develop improved **T-D processes** around connections, planning, shared TSO/DSO services and operation
2. Assess the gaps between the **experience our customers** currently receive and what they would like and identify any further changes to close the gaps within the context of 'level playing field' and common T & D approach
3. Develop a more detailed view of the required **transition from DNO to DSO** including the impacts on existing organisation capability
4. Consider the **charging** requirements of enduring electricity transmission/distribution systems
5. **Communicate** and engage on Open Networks developments

The ENA Open Networks Project

The Charging Workstream

"To consider the charging requirements of an enduring electricity transmission/distribution system, whose purpose is to facilitate a market place between producers and consumers. Consequently, understanding the drivers of cost and benefits in delivering those requirements. The overall aim is to develop the appropriate whole-system price signals for the TSO-DSO transition."

Short-term – by Summer 2017

1. Identify problems caused for customers through the interaction of current charging arrangements across Transmission and Distribution
2. Capture the root causes of these problems
3. Establish the level of commonality that might be required to resolve identified root causes and deliver project and workstream objectives/goals
4. Develop options to resolve

The above development work is being undertaken whilst reviewing how TSO DSO charging work fits with other industry charging initiatives and in discussion with Ofgem on coordination.

Ofgem Targeted Charging Review / Significant Code Review

Main objectives:

- To consider reform of residual charging for transmission and distribution, for both generation and demand, to ensure it meets the interests of consumers, both now and in future; and
- To keep the other 'embedded benefits' that may be distorting investment or dispatch decisions under review.

Ofgem are launching the SCR to address concerns that the current framework for residual charging may result in inefficient use of the networks.

The scope of the SCR includes:

- Residual charging for transmission and distribution, for both generation and demand; and
- Keeping the other embedded benefits under review.

The scope of the SCR excludes:

- Forward-looking use of system charges;
- Connection charges; and
- Charging arrangements for storage.

Ofgem Targeted Charging Review / Significant Code Review

Process:

Ofgem to direct licensee(s) to raise modification proposal(s). At the end of the SCR phase of the process Ofgem will issue a direction to the relevant licensee(s). The direction may set out high-level principles (with the detail to be developed by industry) or more specific, detailed conclusions to be given effect through code change(s).

Modification(s) to follow standard industry code modification processes.

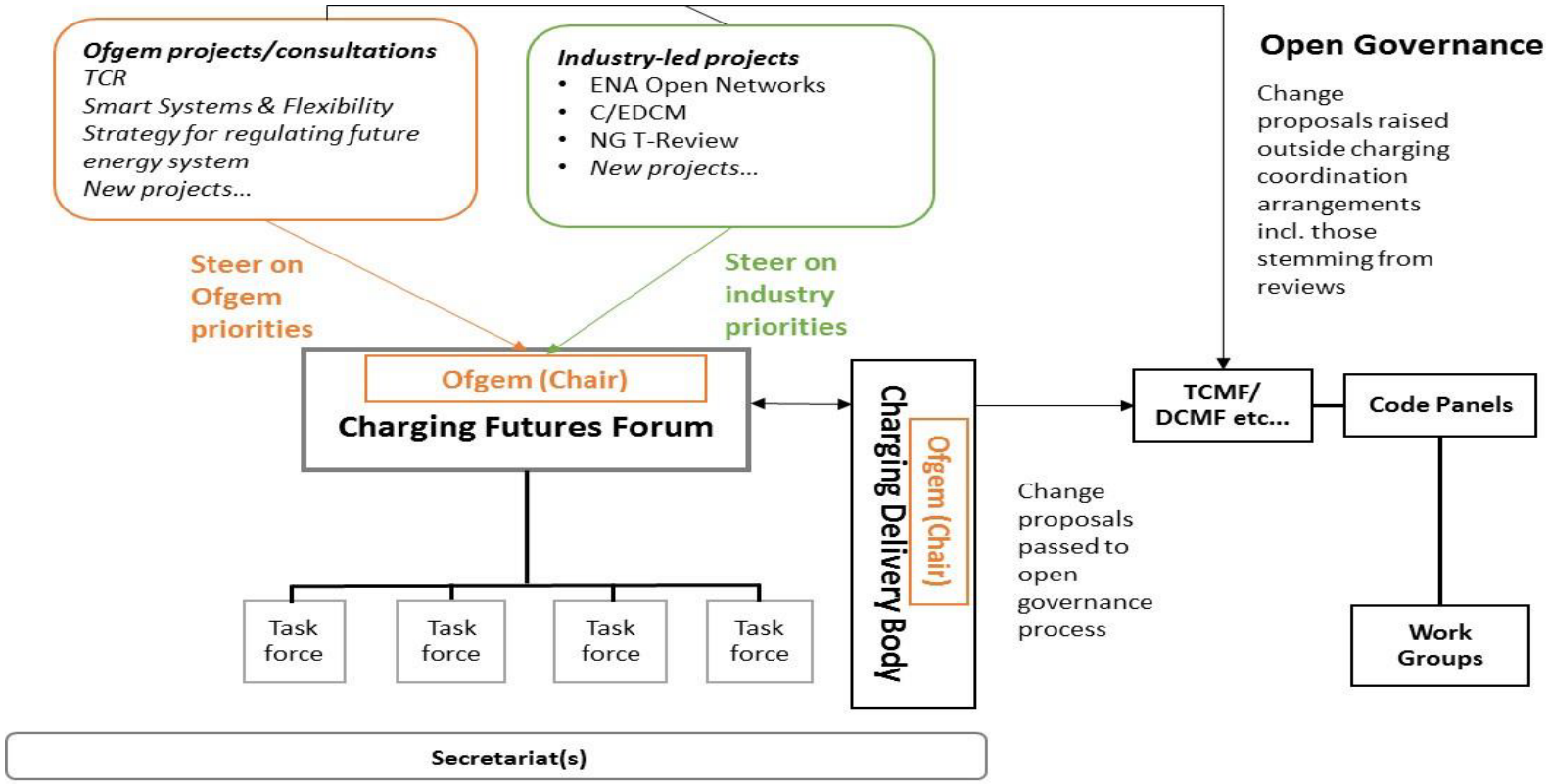
Timeline:

1. Publish residual charges working paper - **Q4 2017** (calendar year)
2. Publish draft Impact Assessment and minded to decision on any proposed new residual charging arrangements – **Q2 2018**
3. Publish decision and final Impact Assessment on any new residual charging arrangements – **Q3 2018**

Final phase of the TCR to be led by industry through working groups and code panel meetings.

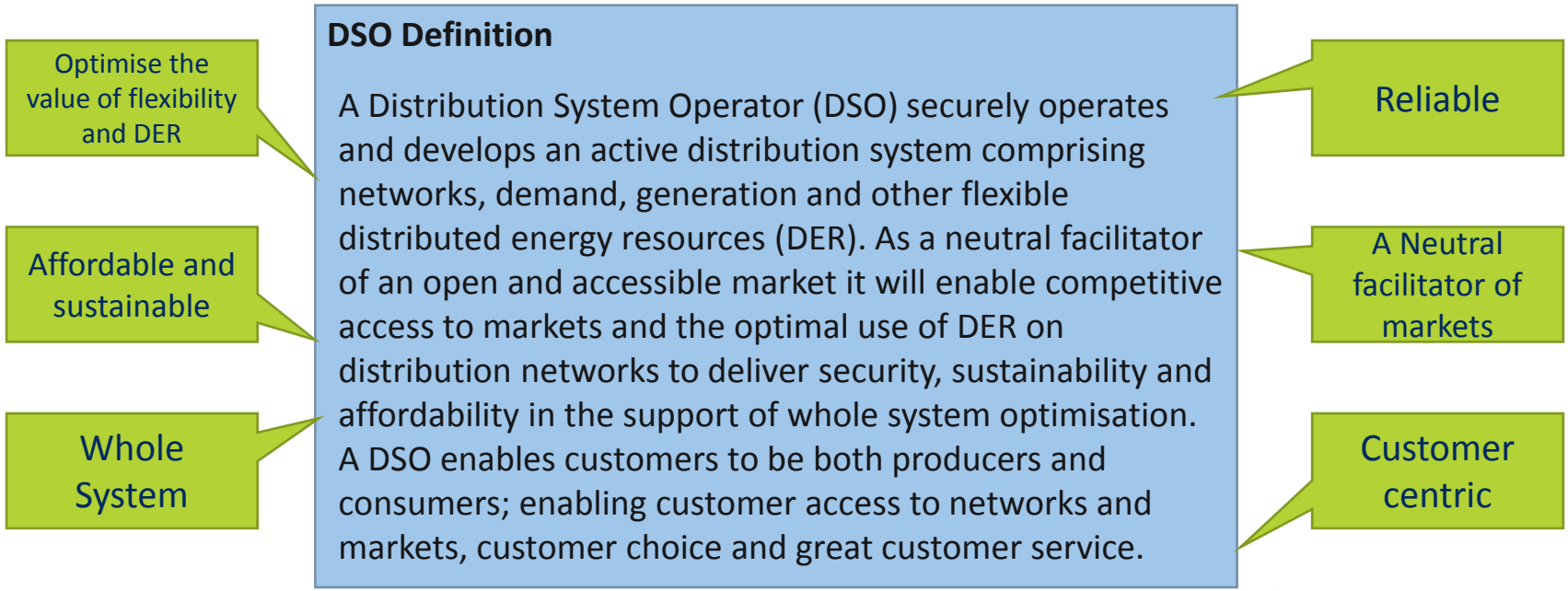
4. Final decision on modifications **early 2019**
5. New arrangements to come into effect from the **2020/2021 charging year**.

Ofgem Targeted Charging Review / Significant Code Review



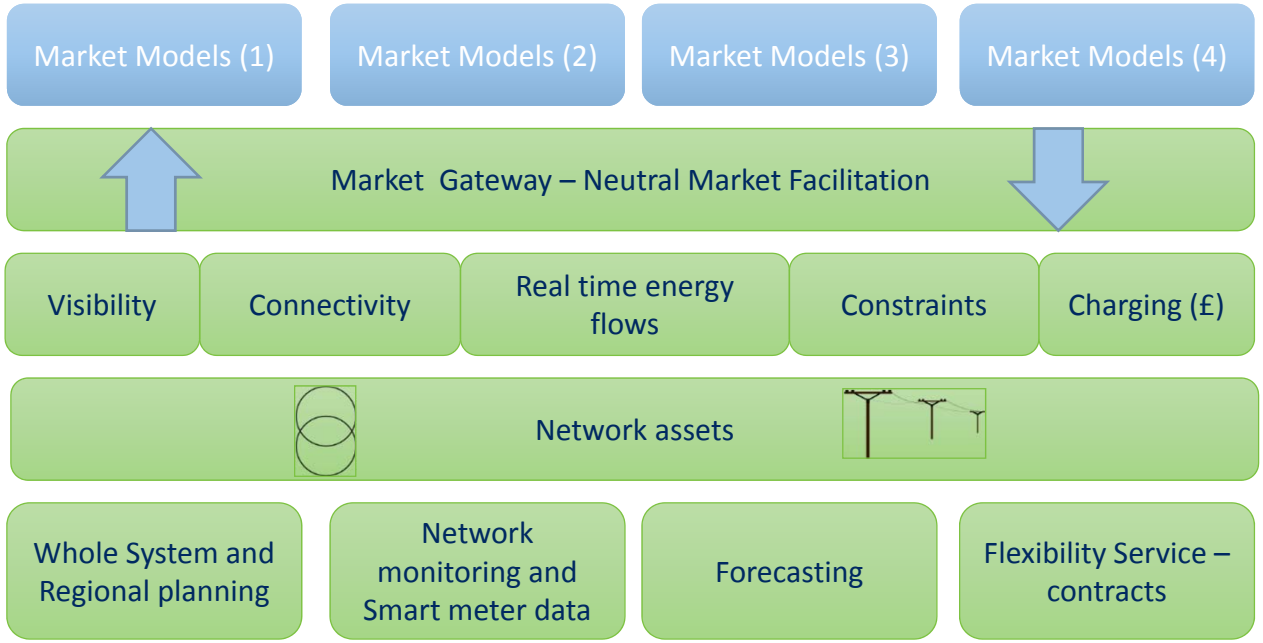
Sorcha Schnittger
Scottish & Southern Electricity Networks

What is a Distribution System Operator?



Scottish & Southern Electricity Networks

Market models



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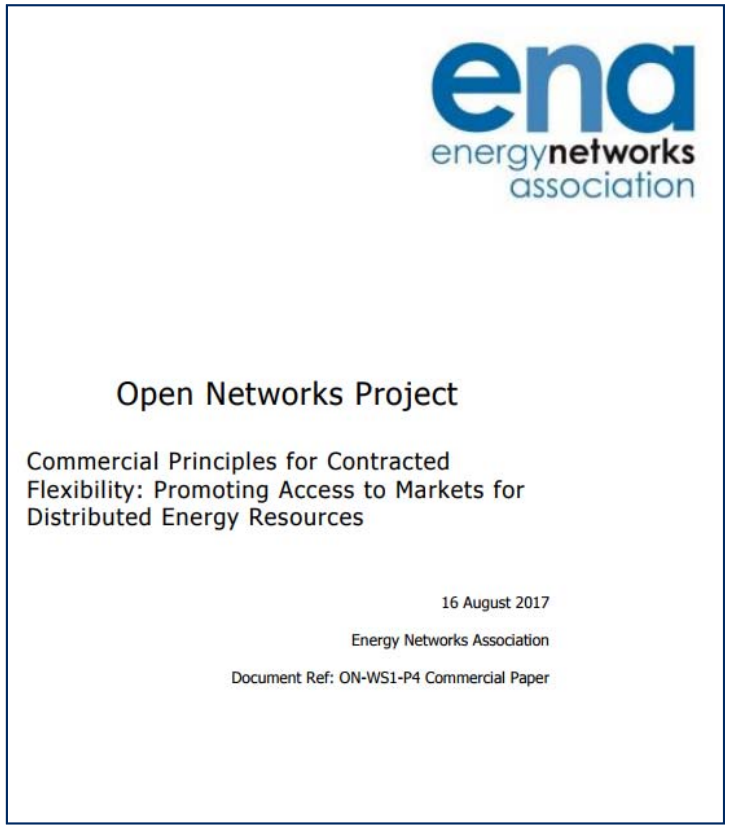

While the focus of this paper is on maximising the use of flexibility provided by DER, this is in the context of enabling them to participate equally alongside other flexibility and balancing service providers, including conventional and renewable transmission connected assets as well as interconnectors.

Responses are welcomed from all market participants and should be submitted to Farina.Farrier@energynetworks.org by 17:00 29th September 2017.

http://www.energynetworks.org/electricity/futures/open-networks-project/ open-networks-project-stakeholder-engagement.html

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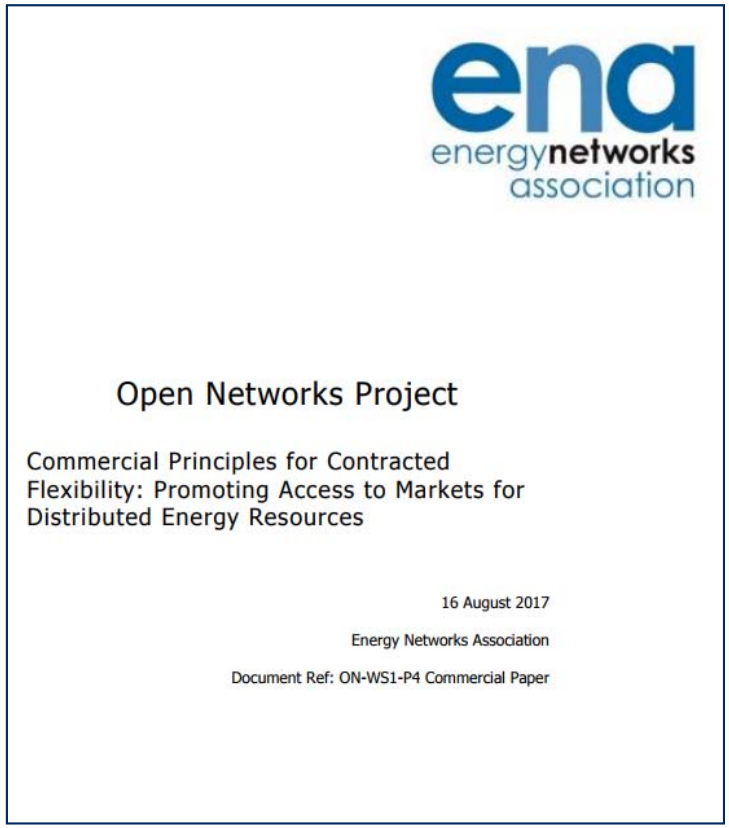

DERs can provide services in a way that improves network coordination and reduces system costs.

- Maximise the use of DER assets,
- Deliver access to markets for all parties
- Encourage new business models
- Maximise the benefits of competition and third-party involvement.

http://www.energynetworks.org/electricity/futures/open-networks-project/ open-networks-project-stakeholder-engagement.html

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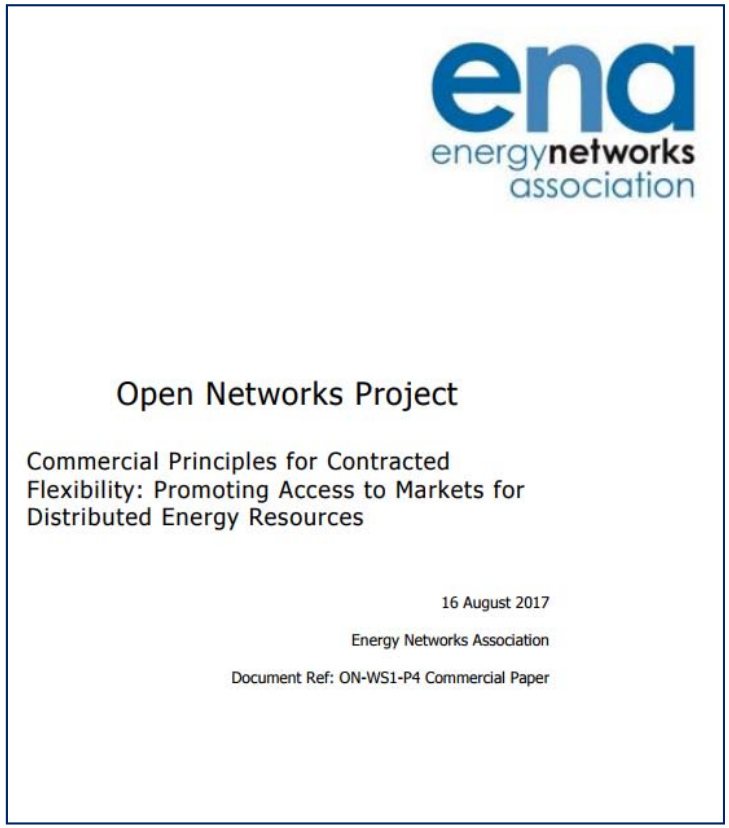

1. What models (procurement and operation) should be used to allow DER to offer multiple services to multiple entities such as the NETSO and DSOs?
2. How can DSOs and the NETSO ensure sufficient visibility and controllability of DER output for managing transmission and distribution network constraints?
3. How can we ensure the various routes to market for DER can coexist and compete in a coordinated way?
4. How should DER curtailment for transmission constraints be treated from a commercial perspective? and
5. How might distribution congestion management activities develop alongside the transition from DNO to DSO?

http://www.energynetworks.org/electricity/futures/open-networks-project/ open-networks-project-stakeholder-engagement.html

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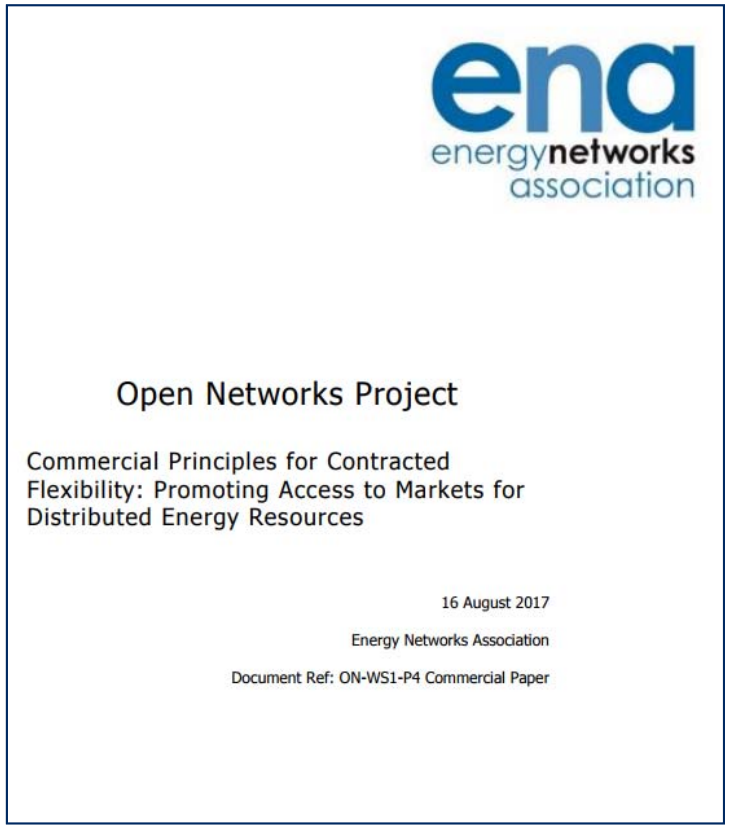
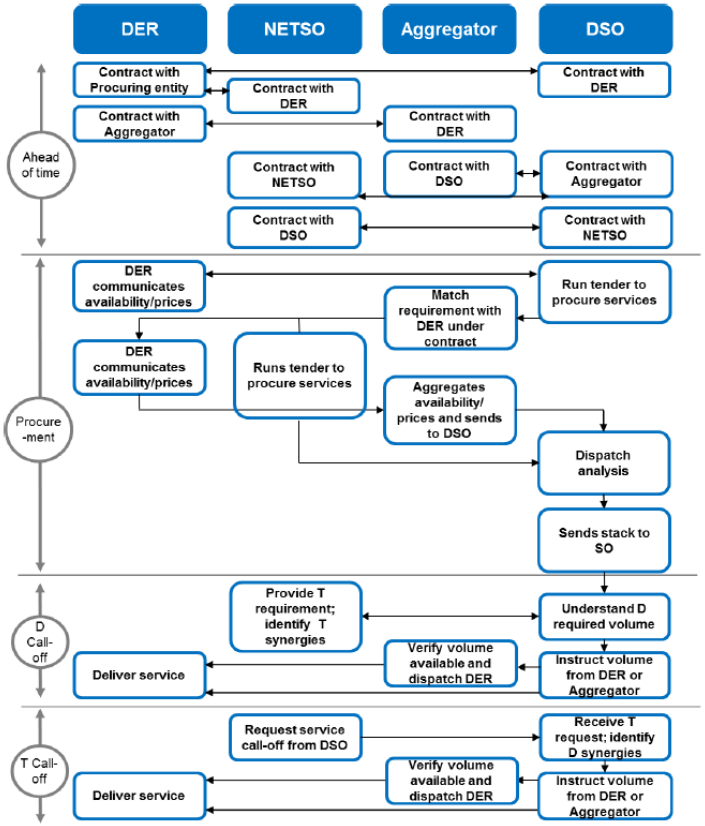


- DER able to offer multiple services to multiple market participants
- Simplicity in how multiple revenue streams can be accessed
- Transmission and Distribution coordination to facilitate service provision from DER to the SO/DSO/Suppliers
- DER and/or Aggregators and Suppliers responsible for providing data to enable contractual settlement
- Market based and transparent services procurement
- Cost efficient outcome for the end consumer.

http://www.energynetworks.org/electricity/futures/open-networks-project/ open-networks-project-stakeholder-engagement.html

Scottish & Southern Electricity Networks



- Five models outlined in the paper.
- Model 5 (shown) is currently being trialled through the Power Potential Project.
- DSO procures the service on behalf of the SO.
- All parties dispatched through a central platform.

http://www.energynetworks.org/electricity/futures/open-networks-project/ open-networks-project-stakeholder-engagement.html

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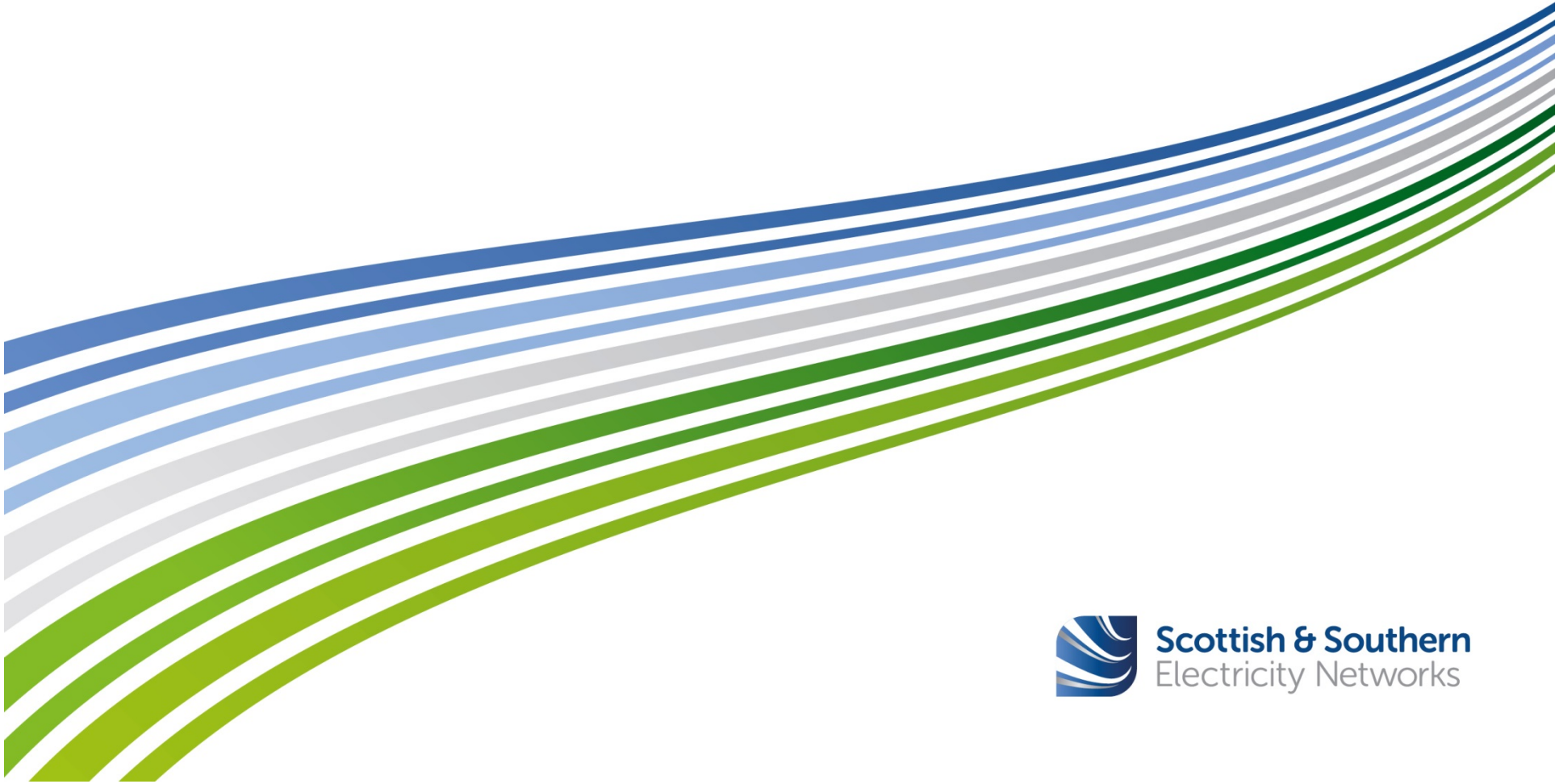


Scottish & Southern
Electricity Networks

Industry Experience

Joseph Dunn
ScottishPower Renewables

SCOTTISHPOWER RENEWABLES

Joe Dunn

30 August 2017

INTRODUCTION TO THE ELECTRICITY NETWORK: CHARGING & REGULATION

Industry Experience

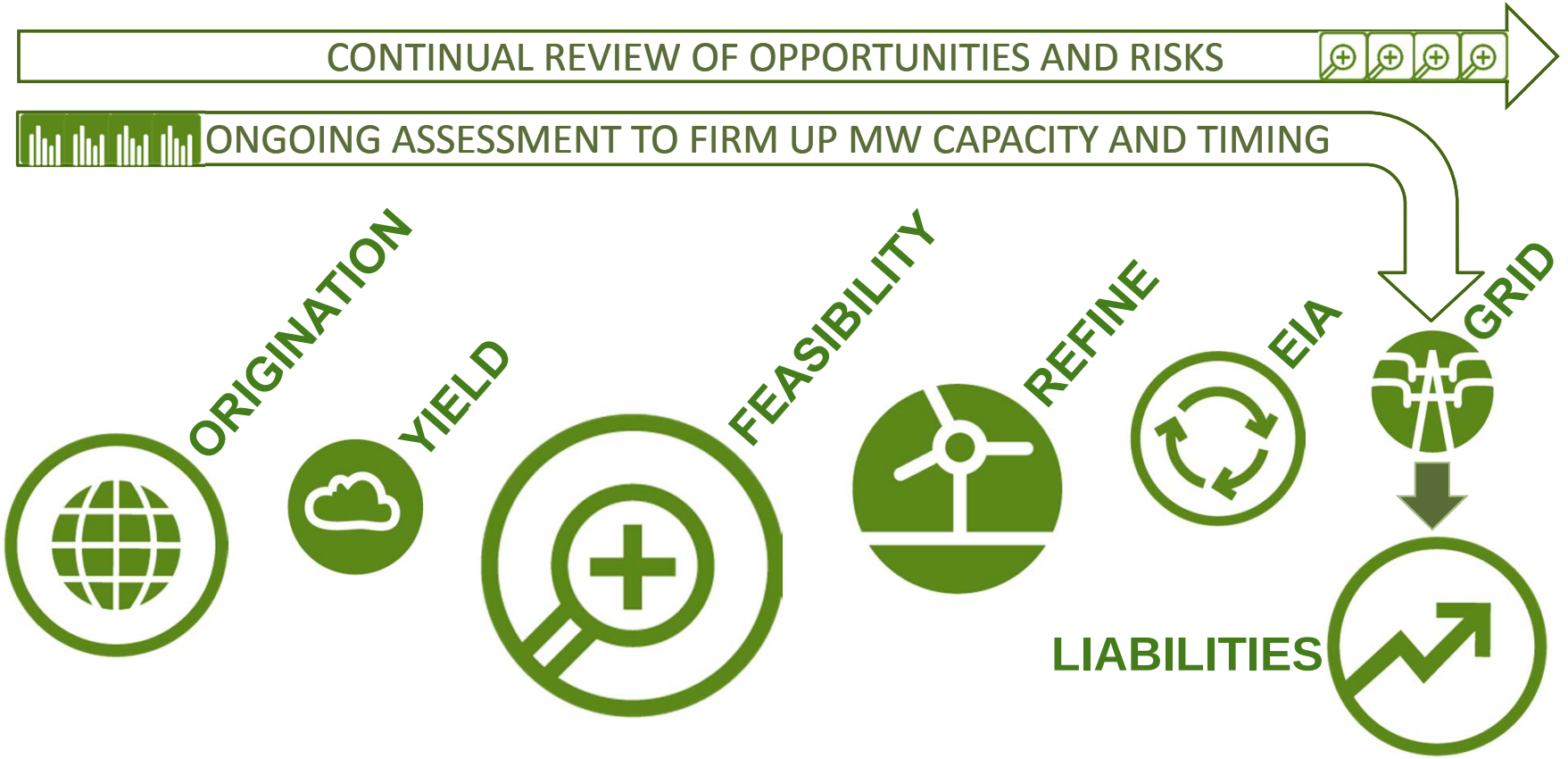
Developing a Windfarm

Grid Optioneering

Beyond Plug and Play

Developing a Windfarm

Developing a Windfarm



Developing a Windfarm (Grid Considerations)

GRID

How much is it going to cost?

- Connection Charges (one-off?)
- Use of System Charges (T/D)
- Liabilities and cash flow
- Contestability or ownership

Certainty

When can I connect?

- Major/ Minor Reinforcement
- Route to Market
- Point of connection
- Transmission or Distribution

Certainty

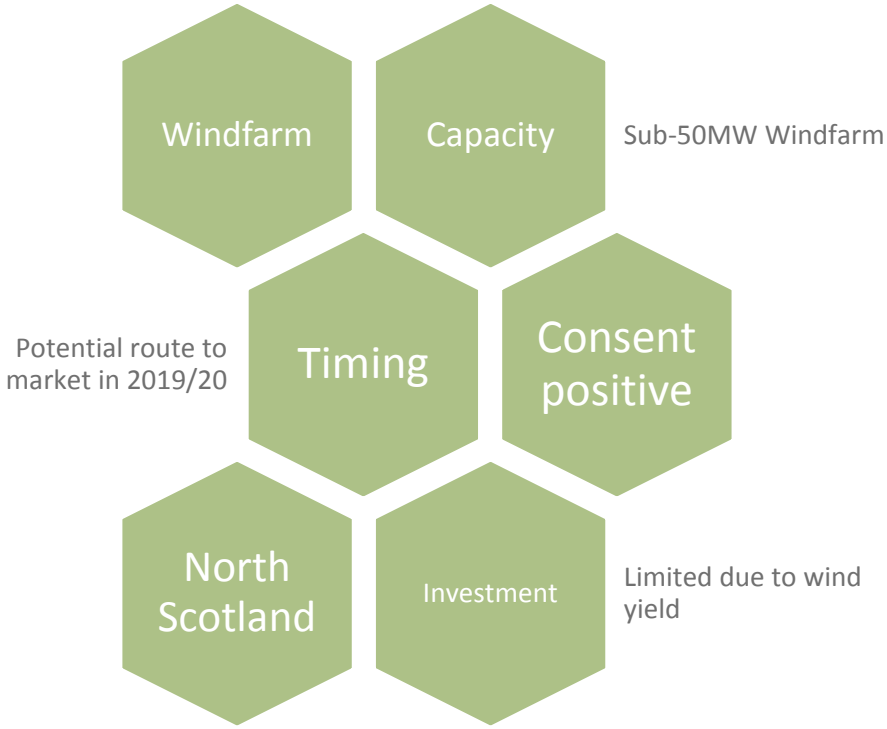
What unknowns are there?

- Consenting
- Changes to Charges
- Probability on restrictions
- CUSC Modifications/ UK Policy

Certainty

Grid Optioneering

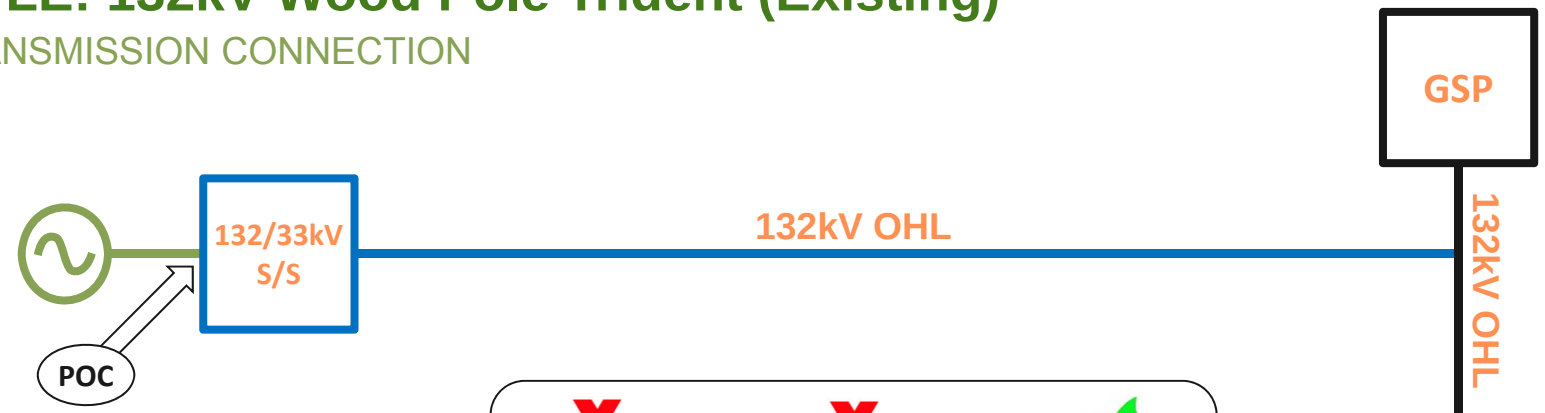
Grid Optioneering – A Hypothetical Scenario



Grid Optioneering of a sub-50MW Connection

TITLE: 132kV Wood Pole Trident (Existing)

TRANSMISSION CONNECTION



- Local and Wider TNUoS v.high
- Long lead time enabling works
- Relative certainty around connection

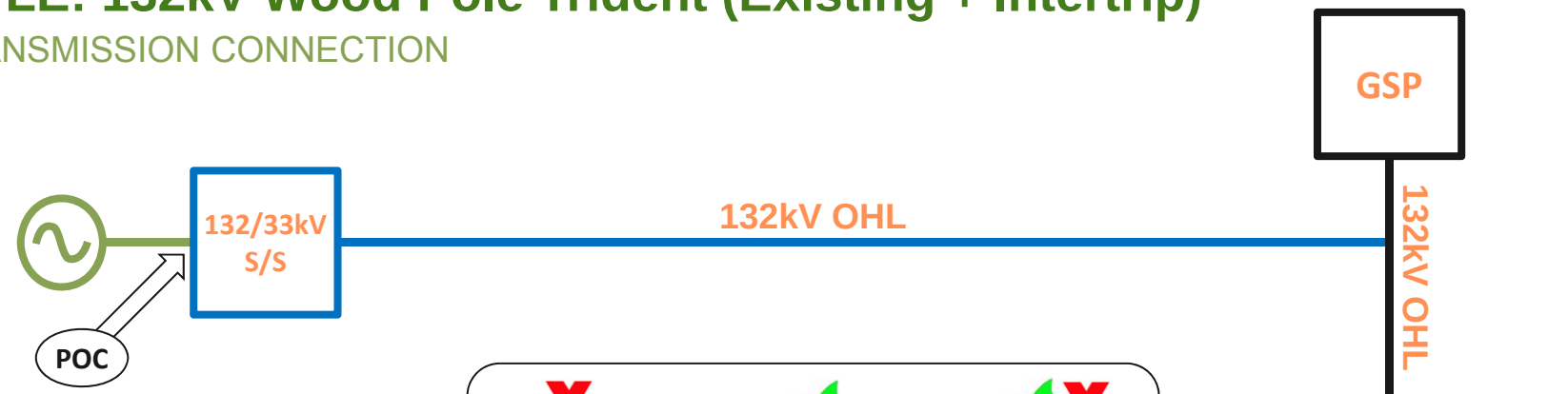
KEY:

- Existing Network
- Network Operator
- Developer (O&M)

Grid Optioneering of a sub-50MW Connection

TITLE: 132kV Wood Pole Trident (Existing + Intertrip)

TRANSMISSION CONNECTION



- Connect earlier on less enabling works
- Local and Wider TNUoS v.high
- Introduce some uncertainty

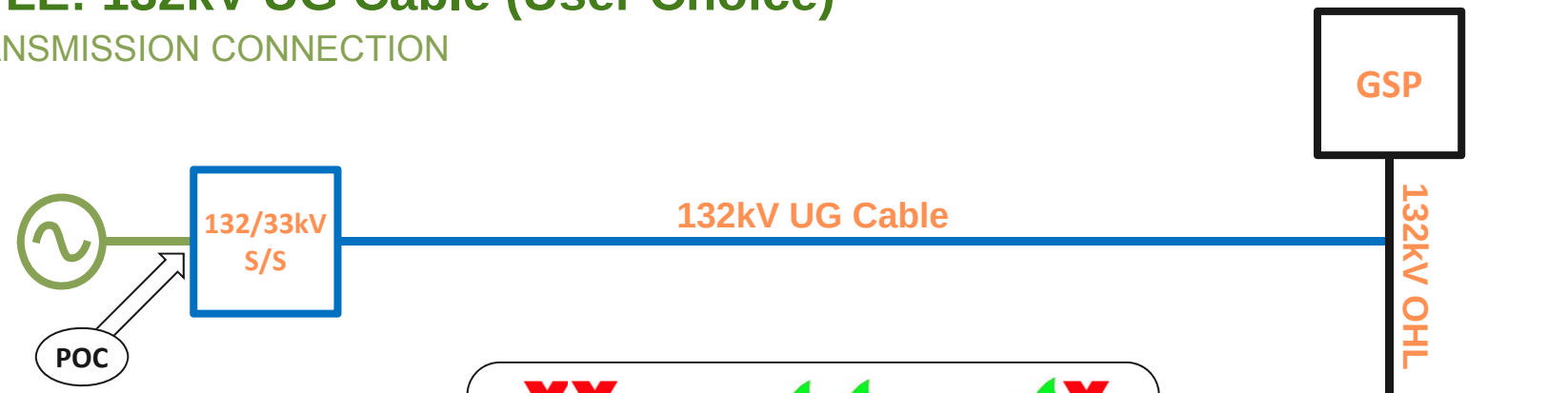
KEY:

- Existing Network
- Network Operator
- Developer (O&M)

Grid Optioneering of a sub-50MW Connection

TITLE: 132kV UG Cable (User Choice)

TRANSMISSION CONNECTION



- Increased one-off costs
- Enabling works delivered earlier
- Remove consenting uncertainty

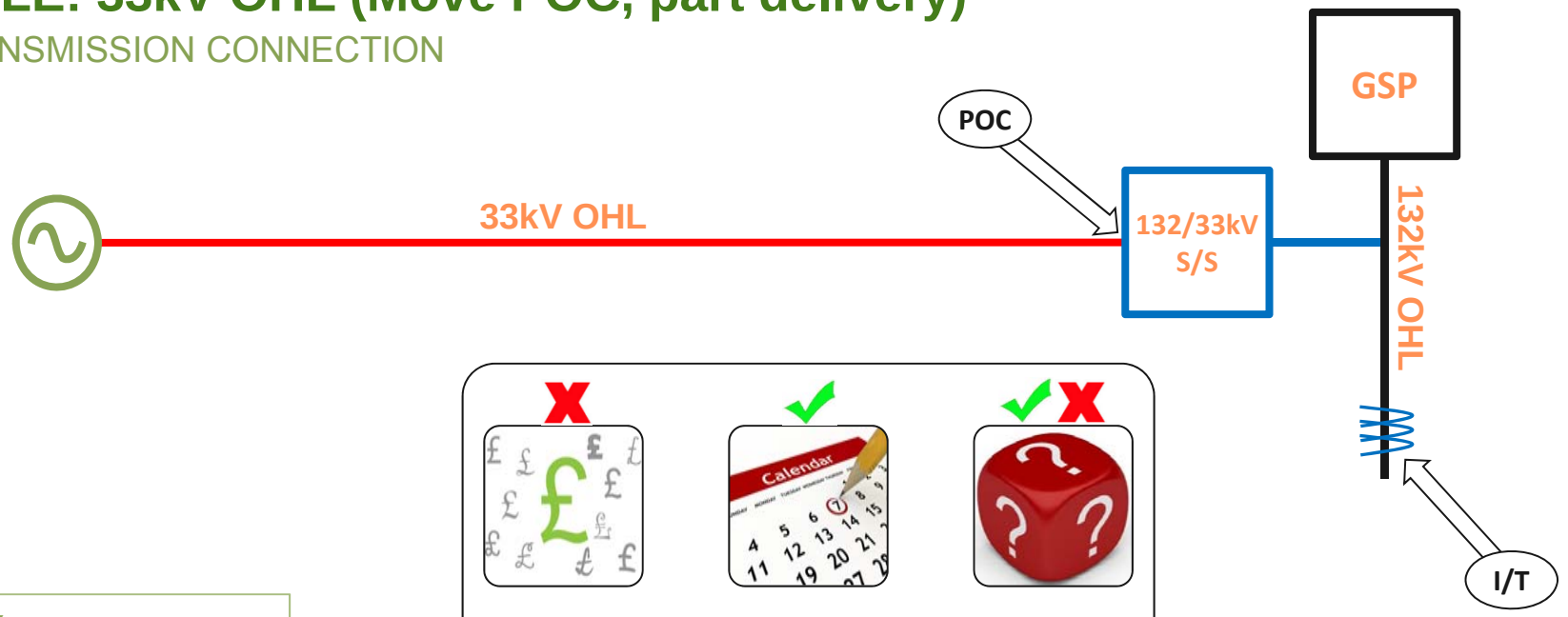
KEY:

- Existing Network
- Network Operator
- Developer (O&M)

Grid Optioneering of a sub-50MW Connection

TITLE: 33kV OHL (Move POC, part delivery)

TRANSMISSION CONNECTION



- 33kV OHL line costs much lower
- Easier to consent (control of delivery)
- S/S still required near 132kV OHL

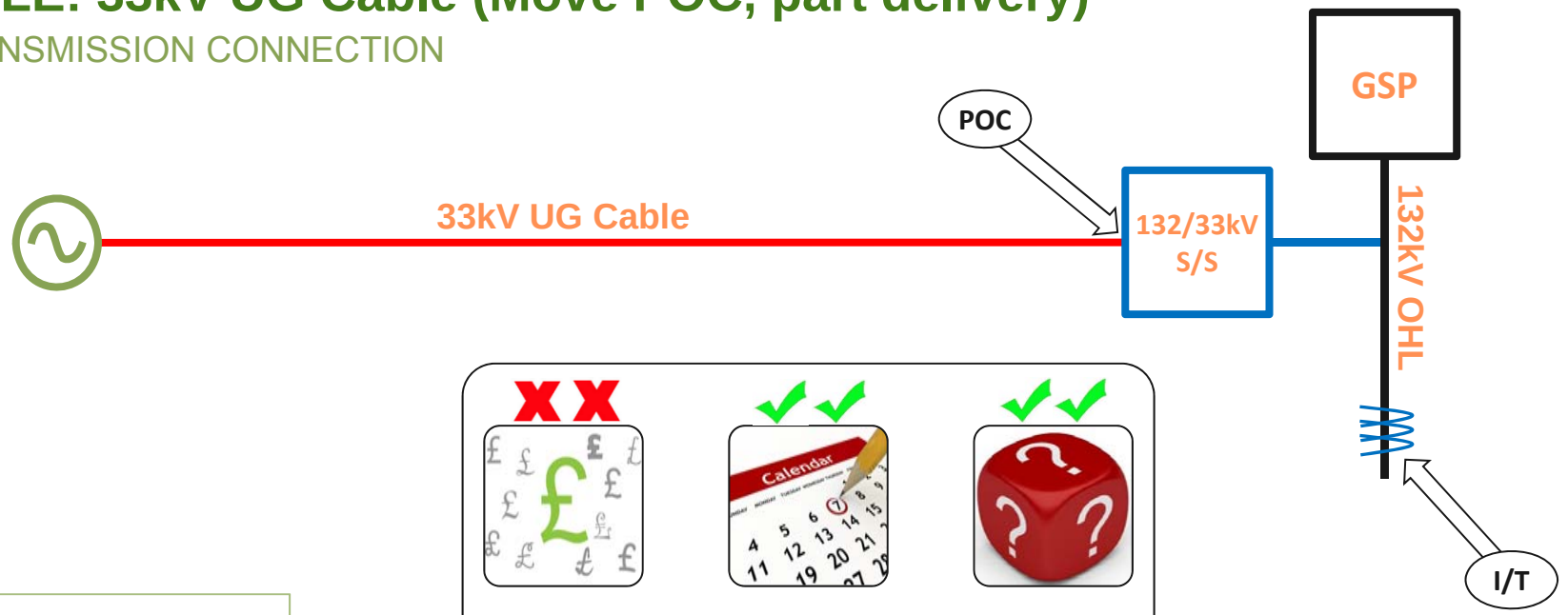
KEY:

- Existing Network
- Network Operator
- Developer (O&M)

Grid Optioneering of a sub-50MW Connection

TITLE: 33kV UG Cable (Move POC, part delivery)

TRANSMISSION CONNECTION



- Cable increases cost
- Minimal consent (control of delivery)
- S/S still required near 132kV OHL

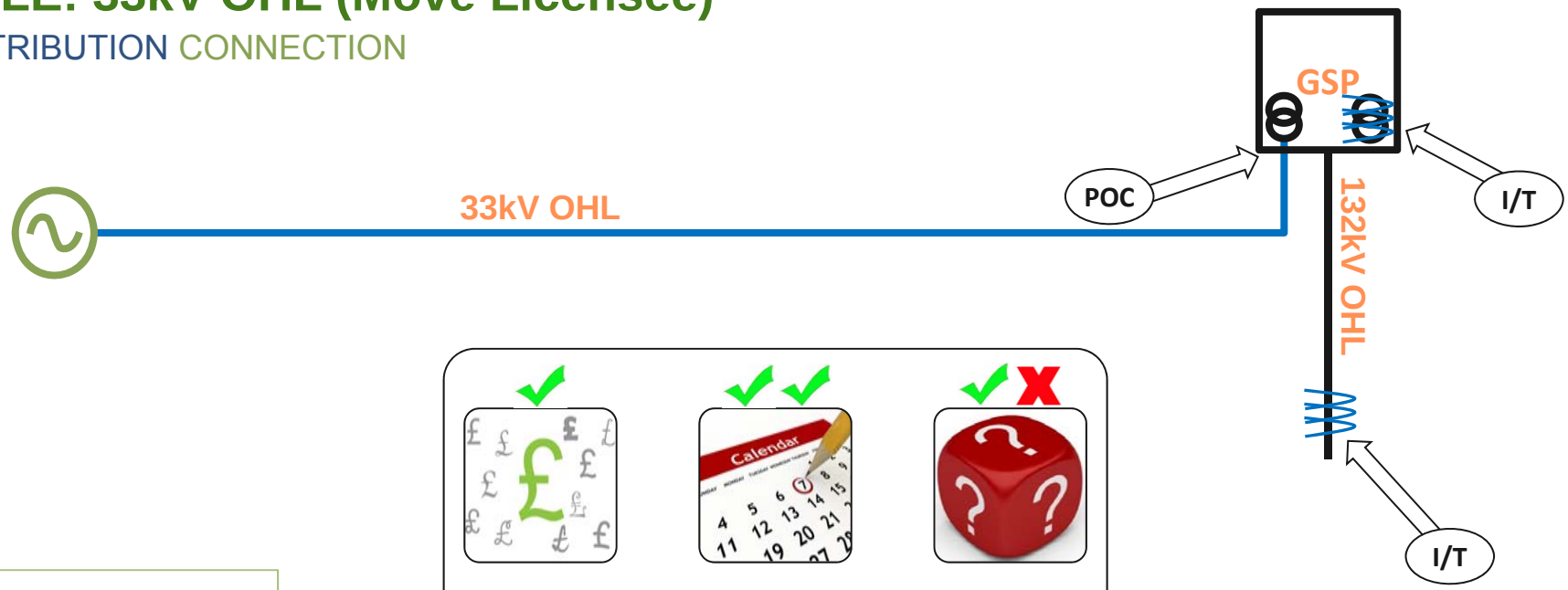
KEY:

- Existing Network
- Network Operator
- Developer (O&M)

Grid Optioneering of a sub-50MW Connection

TITLE: 33kV OHL (Move Licensee)

DISTRIBUTION CONNECTION



- Massive reduction in UoS Charges
- Reduced consent
- Additional Intertrip, UoS uncerainty

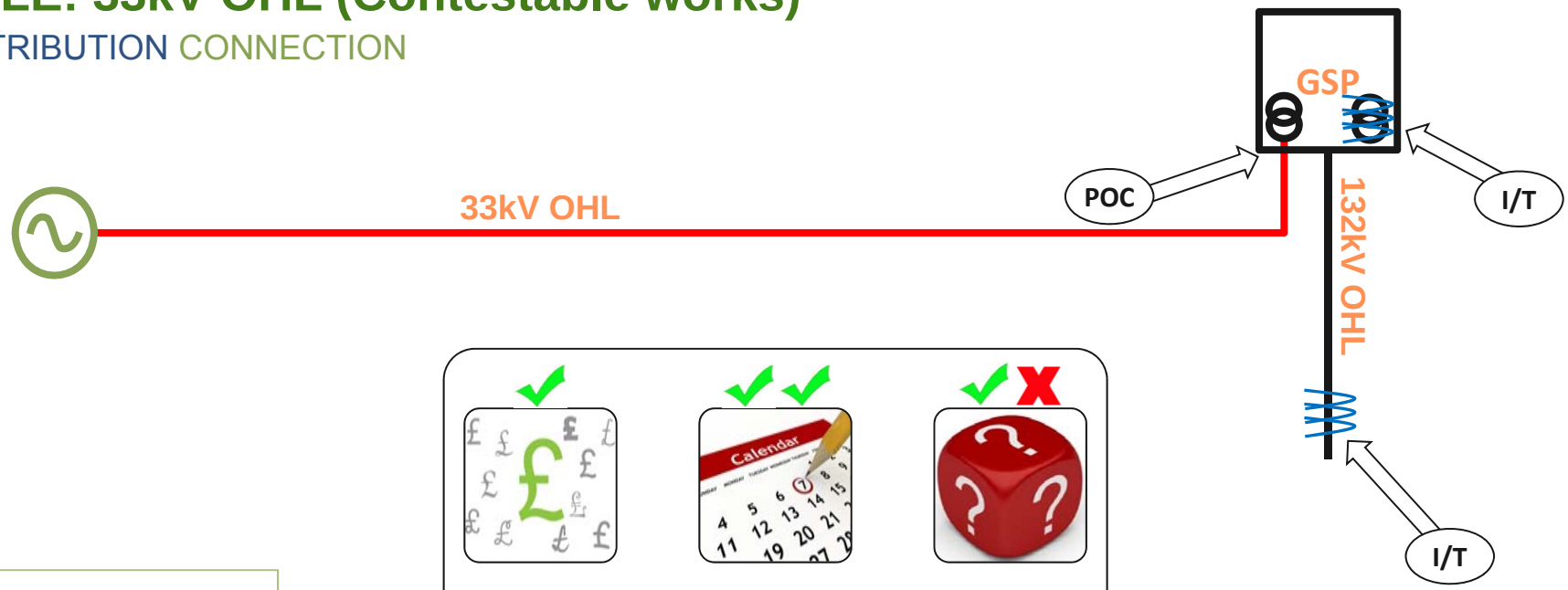
KEY:

- Existing Network
- Network Operator
- Developer (O&M)

Grid Optioneering of a sub-50MW Connection

TITLE: 33kV OHL (Contestable works)

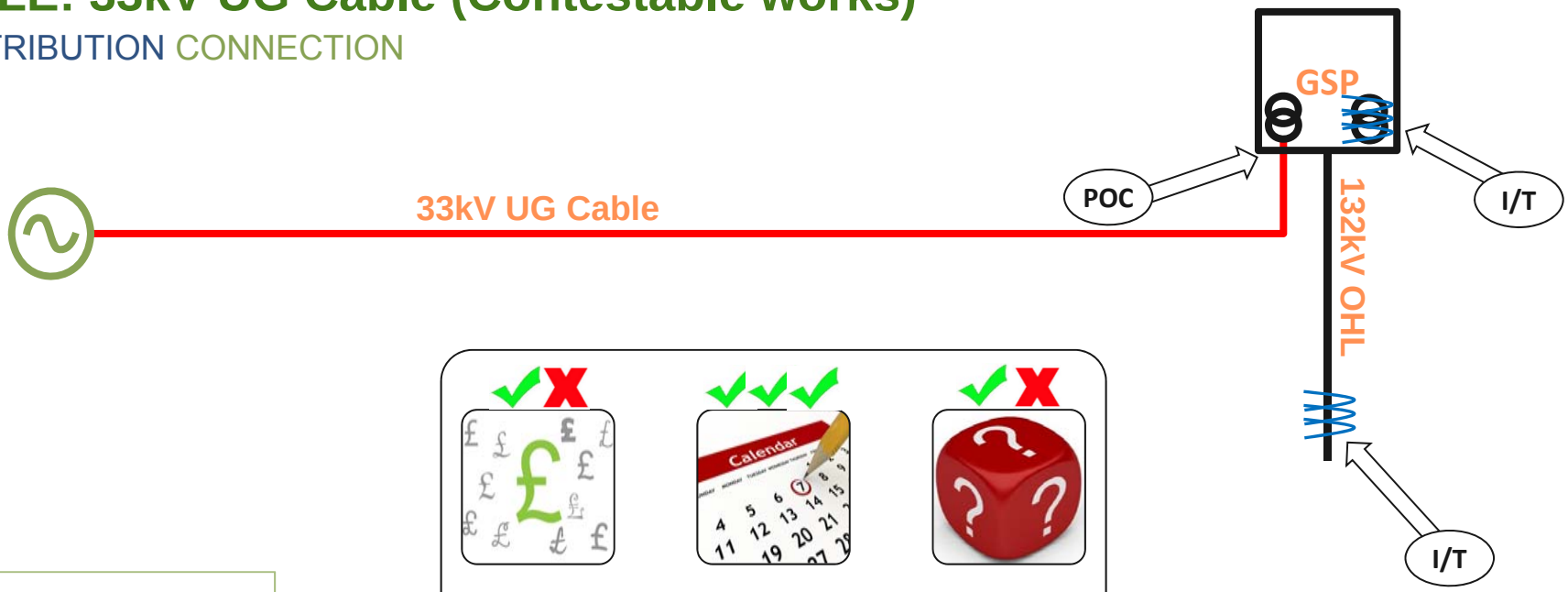
DISTRIBUTION CONNECTION



Grid Optioneering of a sub-50MW Connection

TITLE: 33kV UG Cable (Contestable works)

DISTRIBUTION CONNECTION



- Additional cost
- Remove consent risk completely

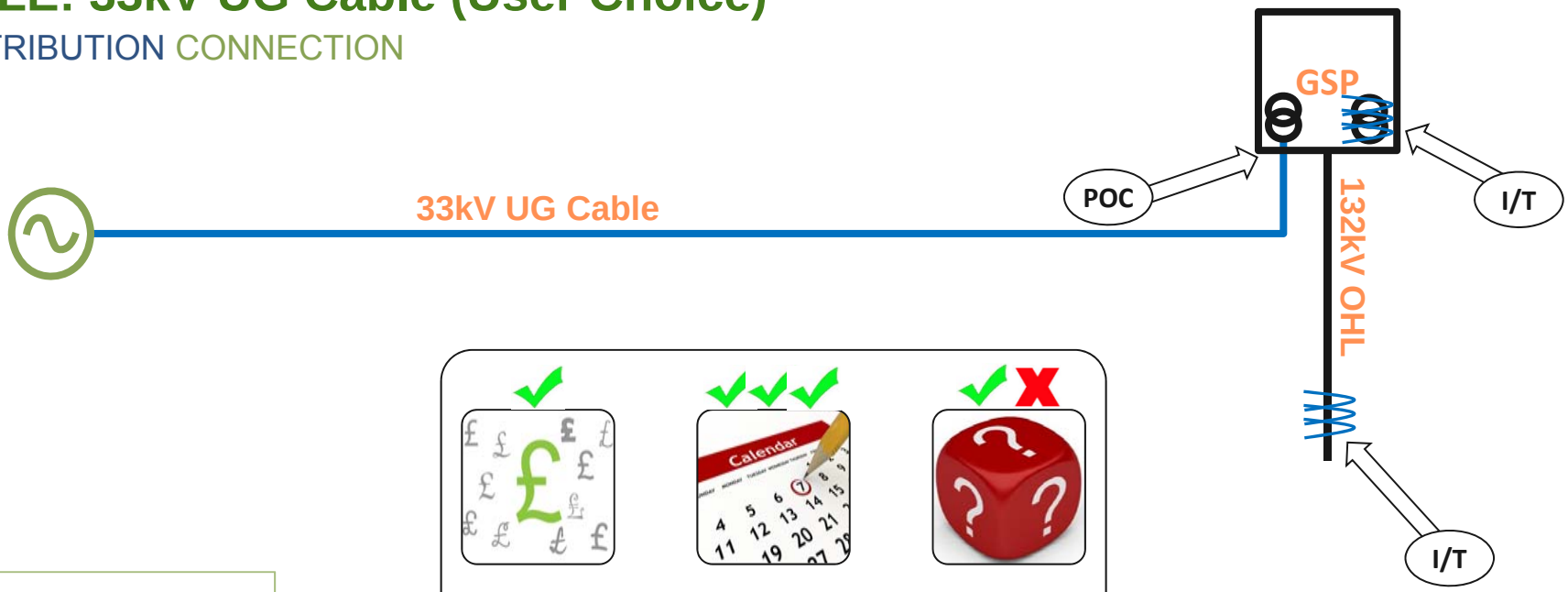
KEY:

- Existing Network
- Network Operator
- Developer (O&M)

Grid Optioneering of a sub-50MW Connection

TITLE: 33kV UG Cable (User Choice)

DISTRIBUTION CONNECTION



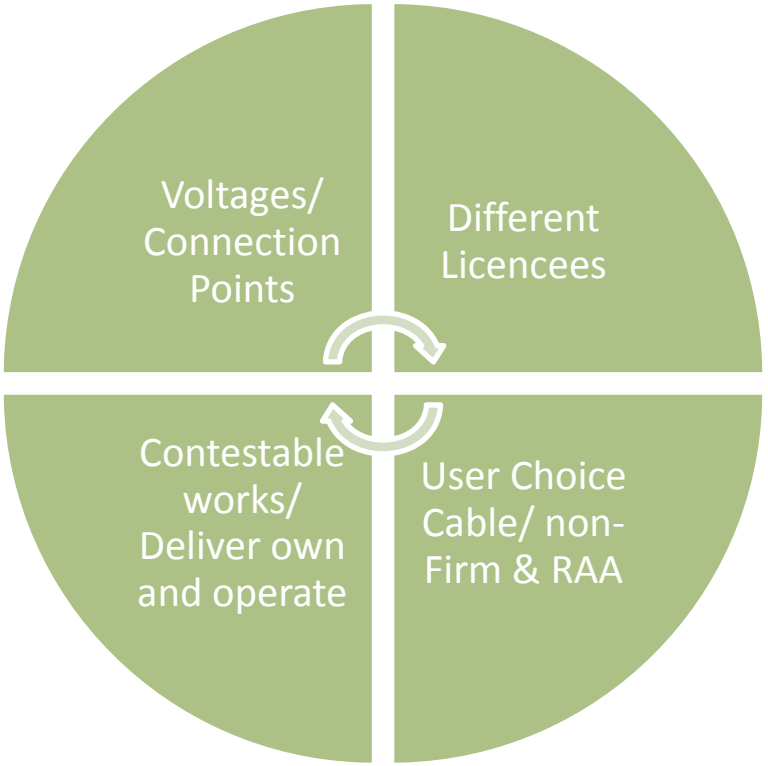
- Remove consent risk completely
- Remove process uncertainty from CW

KEY:

- Existing Network
- Network Operator
- Developer (O&M)

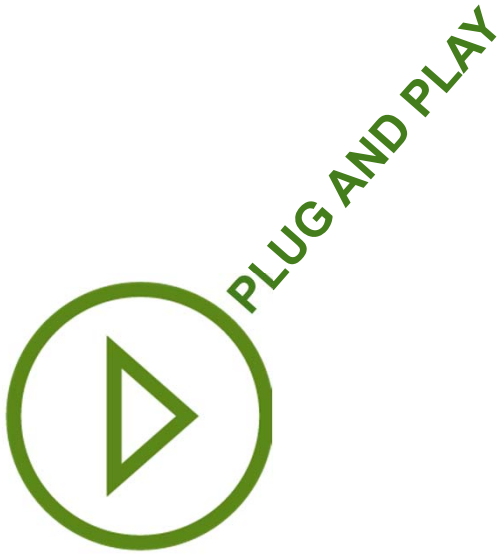
Grid Optioneering of a sub-50MW Connection

GRID CONCLUSIONS & CONSIDERATIONS



Beyond Plug and Play

Beyond Plug and Play

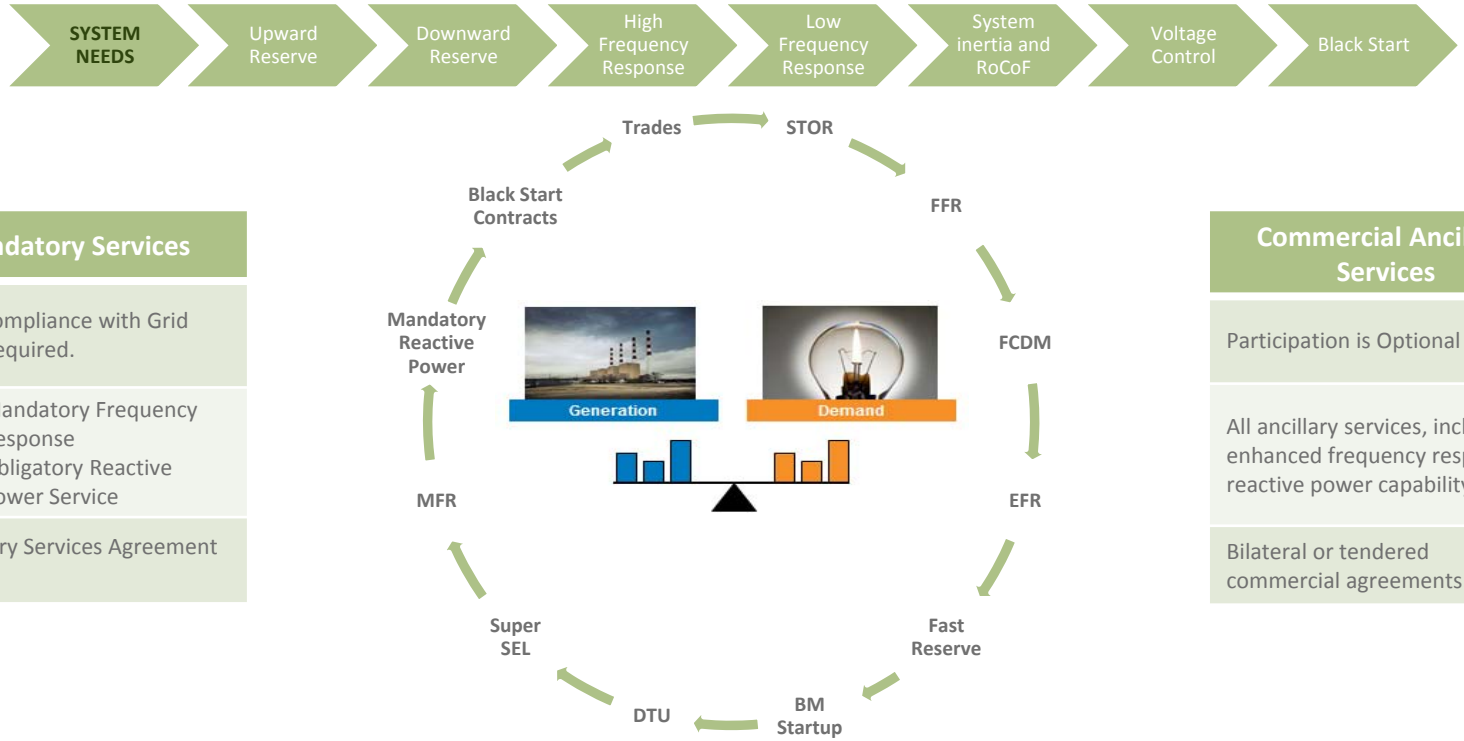


New Technology Renewable Generation
Maximum Active Power Output
BM Participation (Obligatory)
Mandatory Frequency Response
Mandatory Reactive Power
Operational Intertrip (where specified)

- New Renewable Generation was not designed to deliver additional Ancillary Services
- There is no market value or transparency to allow participation beyond the minimum

Beyond Plug and Play: Ancillary Services

Balancing: Secondary to Balancing Mechanism actions National Grid procures Ancillary Services to balance demand and supply and to ensure the security and quality of supply.



Mandatory Services

Where compliance with Grid Code is required.

1. Mandatory Frequency Response
2. Obligatory Reactive Power Service

Mandatory Services Agreement (MSA).

Commercial Ancillary Services

Participation is Optional

All ancillary services, including enhanced frequency response, reactive power capability

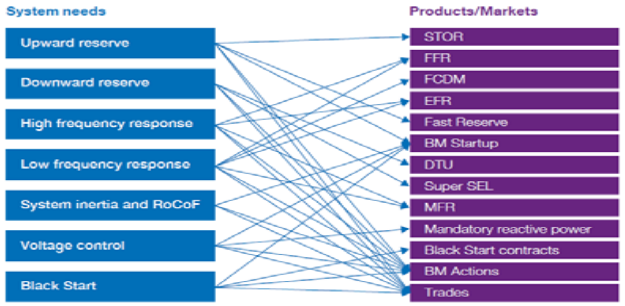
Bilateral or tendered commercial agreements.

Beyond Plug and Play: System Needs and Product Strategy

SNAPS should reform balancing services markets for all technology types to compete on a level playing field

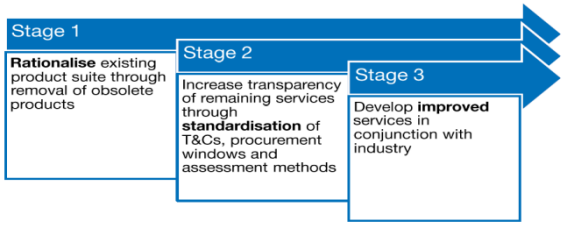
Existing Market

- Too many products all procured in different ways
- Unclear requirements and interactions
- Unclear assessment criteria
- Overlapping markets



Product Strategy Process

- Rationalisation
- Standardisation
- Improvement



Transparent and accessible markets should create a level playing field fit for the current and future mix of generation

Beyond Plug and Play What can we do now?

New Technology Renewable Generation	
Maximum Active Power Output	
BM Participation (non-BM)	NEW MARKETS/ CONTRACTS
Enhanced Frequency Response	NEW MARKETS
Additional Reactive Power	SOFTWARE HARDWARE UPGRADES
Commercial Intertrips	CONTRACTS
Aggregated Embedded Services (RP, BM)	CONTRACTS/ platforms
Synthetic Inertia	SOFTWARE/ STATCOMS
Black Start	Why Not?

- There is no reason that technology cannot be refined and adapt to provide services
- Markets must adapt to provide flexibility and transparency for participation to work

Beyond Plug and Play

BEYOND PLUG AND PLAY

Industry Experience

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Ask the Experts

Chair

Dr Simon Gill, University of Strathclyde

Speakers

Rob Marshall, National Grid

Paul McGimpsey, Scottish Power Energy Networks

Sorcha Schnittger, Scottish & Southern Electricity Networks

Joseph Dunn, ScottishPower Renewables

Keith Bell, University of Strathclyde

Q & A

Networking Lunch

SR Introduction to the Electricity Network: Charging & Regulation CPD Seminar

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