Charging Futures | Forum

Reforming electricity charging together

Electricity Network Access Project

2nd Forward Looking Charge TF meeting

21 December 2017

Introduction

- Agenda

Task	Timing
Welcome and introductions	10:15 - 10:20
Ensuring successful task force outcomes	10:20 – 10:30
What should a forward looking charge recover?	10:30 – 10:35
Discussion on network topology and cost drivers	10:35 – 11:35
Customer considerations	11:35 - 12:00
Option development – introduction	12:00 – 12:10
Lunch	12:10 – 12:50
Structure of charges – options for change	12:50 – 13:45
Locational and temporal signals – options for change	13:45 – 14:40
Coffee Break	14:40 – 14:55
Whole system charges – options for change	14:55 – 15:50
Meeting wrap up	15:50 – 16:00

- Update from Access TF on 18 December.

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Summary of Access TF 18/12/17

Existing arrangements discussion

Network cost drivers

- Overview of key types of constraint and how outages contribute to these – some discussion about how localised constraints from EVs or heat pumps might be. The view was highly localised.
- TF requested a view of actual and forecast costs across networks, and how drivers these might change

Local network info. and capabilities

- TF felt a clearer view was needed of levels of constraint and visibility of distribution networks across voltage levels, LCT take-up and forecast reinforcement needs
- Potential dependency was flagged about level of DNO access to half hourly smart metering data and notification requirements for connecting new technologies. Specifically, importance of being able to have sufficiently granular view of localised constraints so access/network charges can signal where these occur so network users can respond to them.

Existing access arrangements

- TEC exchanges and some short term products are currently available but little used
- DNO presented ENA Open Netwroks work on entitlements and rights
- TF sought clarity about meaning of the term 'access' and how access rights for demand users are established and compare to diversity assumptions

Key actions: Network operators to

- Clarify cost drivers and visibility and monitoring network developments
- Provide their view of existing arrangements for network access, including standard terms and conditions

Summary of Access TF 18/12/17

Access options - considering the building blocks

Choice of access options

- The TF discussed potential options for choices in network access options.
- They discussed what the respective roles in obtaining / paying for access to network areas (eg role of suppliers or DNOs in getting access for distributed resources to the transmission system) and managing different access options for consumers.
- Some options are already possible and utilized in a limited way – typically bilaterally.
- Discussion of how local rights would interact with energy markets, noting similarities with LMP

Initial allocation

- Discussion of TAR '4th model' – some feasibility challenges discussed with forecasting long term capacity requirements / load factor / constraint bid/offer price for generators
- Need to consider how short term access would be charged to ensure fair contributions
- TF discussed some strengths of existing arrangements (locational TNUoS signal + BM)
- TF noted more locational charges (eg BSUoS) could have benefits – further thought needed.

Reallocation mechanisms

- TF discussed potential benefits and risks of 'commoditizing' capacity.
- Trading of financial rights may be more feasible than physical given need to calculate exchange rates, but routes needed to manage risk eg FTRs.
- Discussed how transmission (BM) approach could be applied to distribution, while noting potential practical constraints (eg insufficient information about lower voltage levels)
- Pricing signals via suppliers through smart meters, with emerging scope for aggregated BMUs discussed as potential alternatives - would need to consider interactions with entry capacity.

Key actions: Groups to develop further options for households and, separately, larger users across the three building block categories

Ensuring successful task force outcomes

Task force objectives

- We are committed to consulting on our initial proposals for reform in Summer 2018.
- The TF is one of the inputs that we wanted to use to inform our thinking.
- To meet these timescales the TFs needs to make progress immediately. We want to review the draft sections of the document at the Jan TF.

Date	Task
Dec 2017/Jan 2018	Produce a document identifying the initial options agreed for further assessment.
Feb/March 2018	Produce a document assessing each of the detailed options, based on the agreed assessment criteria.
End of April 2018	Produce a report outlining the TF's conclusions on what changes should be taken forward.

- To make this work will need members to contribute outside of TF meetings

The TF Terms of Reference states…

*"TF Members will… (e) **actively contribute** towards the work of the TF outside of TF meetings; (f) be expected to **contribute** towards the TF milestones."*

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Facilitating TF member contributions

- We are working with the ENA and NG to provide briefing information on the existing arrangements and previous reviews of charging/access.
- For future meetings we intend to provide TF documents five working days prior to each meeting, so that you have time to review.
- We want to provide more direction on required TF work:
  - Flagging more clearly our expectations on future work in agendas/meeting documents
  - Engaging with those taking actions to help the work meet our needs
- Unless agreed otherwise, our expectation is that all TF Members should be contributing to work outside of the TF meetings. Given that other parties are keen on becoming TF Members, if existing TF Members fail to contribute then the Chair may review TF Membership.

Question: Can we do anything else to help you actively contribute towards the work of the TF?

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What should a forward-looking charge recover?

Forward-looking charge

Key principle: What should a forward-looking charge recover?

> They should reflect future network costs that can be influenced by the actions of network users. The charge sends a signal to influence future behaviour.

Principles for determining whether which costs should be signalled through forward looking charges

> **Is it a future cost**: Forward looking charges should only apply to future costs and not to historic/existing costs

> **Can user behaviour affect the cost**: If user behaviour will not affect costs then there is no vale to be realised from attempting to signal user behaviour with a charge

> **Can the cost be allocated**: Some costs e.g. costs associated with frequency management or overhead costs cannot be easily allocated to specific users.

Do you agree with these?

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Network topology and cost drivers

Network topology

Network topology (i.e. the way in which constituent parts are interrelated or arranged) is defined by the following characteristics:

- Industry and company planning and design standards (both existing and historic),
- Company’s materials and equipment specifications (both existing and historic),
- Number of customers,
- Type of customers,
- Customer, load and generation densities,
- Connections to Transmission assets (e.g. National Grid, Scottish Power and Scottish Hydro),
- Proximity to other utilities’ assets,
- Environmental factors, for example height above sea level, ground conditions, proximity to water courses, rivers and estuaries, within or near to National Parks or Areas of Outstanding Beauty etc.

Current network user information
(from CDCM and EDCM)

		Electricity North West	Northern Powergrid (Northeast)	Northern Powergrid (Yorkshire)	SHEPD	WPD East Midlands	WPD South Wales	WPD South West	WPD West Midlands	Eastern Power Networks	London Power Networks	South Eastern Power Networks	SEPD	SP Distribution	SP Manweb	**Total**
Low Voltage - Domestic	MWh	7,688,130	4,949,441	7,315,323	3,169,616	9,328,353	3,533,003	5,537,543	8,821,143	13,193,544	7,074,737	8,206,092	11,340,798	6,958,454	4,938,601	**102,054,775**
Low Voltage - Domestic	MPANs	2,244,286	1,519,386	2,150,125	782,733	2,523,944	1,040,369	1,475,827	2,319,033	3,413,937	2,109,395	2,138,711	2,882,035	2,016,609	1,400,767	**28,017,158**
Low Voltage - Domestic	Capacity kVA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Low Voltage – Small Non-Domestic	MWh	2,390,140	1,214,715	2,182,037	1,038,665	3,186,170	1,113,952	1,726,967	2,364,056	3,896,758	3,465,419	2,288,563	3,449,043	2,128,450	1,631,311	**32,076,246**
Low Voltage – Small Non-Domestic	MPANs	161,021	94,674	138,766	66,964	180,524	78,107	141,790	180,207	254,132	267,382	173,045	229,679	128,098	98,635	**2,193,024**
Low Voltage – Small Non-Domestic	Capacity kVA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Low to High Voltage – Other Non-Domestic	MWh	9,224,761	6,156,650	9,233,210	2,857,032	11,659,243	3,689,383	4,959,165	11,259,126	12,127,259	13,215,324	6,698,785	11,507,808	7,446,505	4,390,325	**114,424,575**
Low to High Voltage – Other Non-Domestic	MPANs	21,512	21,314	19,096	8,204	20,558	8,748	16,004	28,907	31,093	22,326	18,479	29,423	17,409	12,667	**275,740**
Low to High Voltage – Other Non-Domestic	Capacity kVA	4,226,858	2,739,467	3,979,267	1,240,845	4,908,673	1,468,095	2,031,542	4,614,543	5,224,744	6,034,752	2,744,922	5,230,127	2,993,468	1,898,411	**49,335,713**
Unmetered Supplies	MWh	307,893	208,842	292,718	129,276	324,722	150,714	138,467	325,190	353,347	225,705	209,816	261,449	377,447	209,939	**3,515,526**
Unmetered Supplies	MPANs	666	1,283	766	4,067	3,171	1,391	1,566	1,831	3,948	755	1,269	3,461	4,938	633	**29,743**
Unmetered Supplies	Capacity kVA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Low to High Voltage – Generation	MWh	923,067	789,083	675,685	2,156,908	890,891	298,521	735,270	800,628	1,036,568	111,632	380,813	1,032,963	941,155	307,925	**11,081,110**
Low to High Voltage – Generation	MPANs	582	319	920	1,497	522	378	1,052	553	1,449	118	376	1,929	602	355	**10,653**
Low to High Voltage – Generation	Capacity kVA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Total	MWh	20,533,991	13,318,730	19,698,973	9,351,498	25,389,379	8,785,573	13,097,413	23,570,144	30,607,475	24,092,816	17,784,068	27,592,061	17,852,011	11,478,101	**263,152,233**
Total	MPANs	2,428,067	1,636,976	2,309,672	863,465	2,728,719	1,128,993	1,636,239	2,530,531	3,704,558	2,399,977	2,331,881	3,146,527	2,167,656	1,513,057	**30,526,319**
Total	Capacity kVA	4,226,858	2,739,467	3,979,267	1,240,845	4,908,673	1,468,095	2,031,542	4,614,543	5,224,744	6,034,752	2,744,922	5,230,127	2,993,468	1,898,411	**49,335,713**
EDCM Total	Customer count	95	56	135	305	250	187	292	78	208	39	86	318	111	221	**2,381**

Network constraints

Drivers of network constraints (driven by both demand and generation) are:

- Thermal capacity,
- Voltage headroom,
- Fault level restrictions
- Reverse power capability
- Network resilience (e.g. N-1 etc.)

Drivers of Network Costs

The 'old days'	Current	Future

The 'old days'

- Electro-mechanical monitoring
- Demand driven network
- Peak demand driven reinforcement
- Tariff support in connection charging

Current

- Electronic monitoring & network protection
- Distributed generation established.
- Battery storage emerging
- Peak DG /demand reduction
- DG Network constraints
- Flexible connections
- ANM capital and licencing
- Shallowish connection charging with any reinforcement partly socialised
- Choice of asset installers and owners

Future

- Increase in network monitoring
- Smart network support from DER
- DSO manages peak
- Constrained DG vs Reinforcement
- More ANM
- Whole network management TSO/DSO
- Stronger locational signals in connection charges?

Cost Drivers (initial thinking)

Current	Future
Peak demand reinforcement (locational variation)	Peak demand reinforcement or DSO solution for EVs, electric heating and localised growth. Assistance from storage.
Asset Replacement – condition/ age related.	Asset replacement sized for demand or DG growth (timing assisted by DSO).
System automation for better fault management.	More granular automation for fault management.
Roll out of more granular system monitoring.	System monitoring informs DSO actions and required services.
Customer connections triggering cost shared reinforcement.	Revised connection charging rules? and managed access.
Other network innovation.	Further network innovation.
Minimum scheme investment where future is fairly stable	Options/minimum regret based investment to manage an uncertain future

Cost categories and influences

Load related	Connections within the price control
	Reinforcement (Primary Network)
	Reinforcement (Secondary Network)
	Fault Level Reinforcement
	New Transmission Capacity Charges
Non-load capex (excluding non-op capex)	Diversions (Excluding Rail Electrification)
	Diversions (Rail Electrification)
	Asset Replacement
	Refurbishment no SDI
	Refurbishment SDI
	Civil Works Condition Driven
	Operational IT and telecoms
	Blackstart
	BT21CN
	Legal & Safety
	QoS & North of Scotland Resilience
	Flood Mitigation
	Physical Security
	Rising and Lateral Mains
	Overhead Line Clearances
	Worst Served Customers
	Visual Amenity
	Losses
	Environmental Reporting
Non-op Capex	IT and Telecoms (Non-Op)
	Property (Non-Op)
	Vehicles and Transport (Non-Op)
	Small Tools and Equipment
HVP	High Value Projects DPCR5
	High Value Projects RIIO-ED1
Moorside	Moorside

Network Operating Costs	Faults
	Severe Weather 1 in 20
	ONIs
	Tree Cutting
	Inspections
	Repair and Maintenance
	Dismantlement
	Remote Generation Opex
	Substation Electricity
	Smart Metering Roll Out
Closely associated Indirects	Core CAI
	Wayleaves
	Operational Training (CAI)
	Vehicles and Transport (CAI)
Business Support Costs	Core BS
	IT& Telecoms (Business Support)
	Property Mgt
Other costs within Price Control	Atypicals Non Sev Weather
	Atypicals Non Sev Weather (excluded from Totex)
	Network Innovation Allowance (NIA)
	Network Innovation Competition (NIC)
	IFI & Low Carbon Network Fund
Costs outside Price Control	Directly remunerated services (excluding connections, other consented activities, legacy meters and de minimis)
	Smart Meters
	Legacy meters
	De Minimis
	Other consented Activities
	Connection costs outside of the price control
	Out of Area Networks
	Atypicals Non Sev Weather (Non Price Control)
NABC	Pass through
	Other Non Activity Based Costs

Closely driven by customer behaviour
Influenced by customer behaviour
Intrinsic Cost

Discussion points

> Given the principles for forward-looking charges (future cost, user behaviours influence the cost, costs can be allocated), which types of cost should be signalled through forward-looking charges?

Actions

> We need a group volunteers to help develop thinking on the scope of Forward-Looking Charges . The key question to answer is **“What should a forward-looking charge recover?”**

Questions to answer

> **Do the principles** for determining which costs should be recovered via forward-looking charges need to be refined at all?

> Using the principles identified, can you identify **whether the categories of costs identified by the DNOs should be recovered via forward looking charges**? For those cost categories that you are unsure about, what further analysis should be undertaken?

Forward Looking Taskforce
Customer Considerations

Initial thoughts from Citizens Advice

Customer Considerations

- The following slides provide a number of principles that we believe should be considered when developing options within the forward looking taskforce
- These principles relate to domestic customers only and are put forward to encourage discussion

citizens advice

Energy Potential

Households with Electric Vehicles (1)

- Households with electric vehicles typically require higher capacity than those without
- Households that adopt an EV are using up capacity that other households are potentially unable to utilise
- Perception is that only a limited number of households connected to a Low Voltage substation will be able to own a EV without creating reinforcement:
  - Action - DNOs to determine the proportion of households that could charge a EV under different scenarios for a typical LV network for a housing development (e.g. 200 households - charging at peak/ off-peak/ combination)

citizens advice

Energy Potential

Households with Electric Vehicles (2)

Issue – EV households pay the same rate as households without electric vehicles but require a higher capacity:

- Unfair that non-EV households subsidise EV households
- EV households should pay for the higher capacity reserved:
  - Recover through additional capacity charge (factored into fixed charge)
  - Recover through unit rates (incentivised to avoid peak)
  - Combination of above

Potential criteria for consideration

- Additional cost of providing existing and future capacity cost associated with EVs should be recovered from EV households only
- Some additional capacity charge should be introduced as capacity is likely to become the marginal cost driver for EV
- The additional cost should be assessed to determine the impact on consumers

citizens advice

Energy Potential

Vulnerable/ Fuel Poor customers

Issues:

- Network costs likely to continue to increase (EVs/ electrification of heat)
- Greater proportion of network charges to be recovered via fixed/ capacity basis

Both these issues potentially have a larger impact on vulnerable/ fuel poverty customers:

- Customers less able to amend their consumption patterns
- Customers less engaged
- Customers have less understanding of the competitive market

Proposed principle – Separate out vulnerable/ fuel poor customers and introduce a discounted fixed charge

citizens advice

Energy Potential

Potential domestic customers DUoS charging structure

<table>
<tr><th>Customer Type</th><th>Unit Rates</th><th>Fixed charge - Element 1</th><th>Fixed charge - Element 2</th><th>Fixed charge - Element 3</th></tr>
<tr><td>Domestic with EV</td><td rowspan="3">Incorporate forward looking element of charge</td><td rowspan="3">Status quo:
- O&M on sole use assets
- Standing charge factors</td><td rowspan="2">Residual charge (as per TCR)</td><td>Capacity premium</td></tr>
<tr><td>Standard domestic</td><td rowspan="2">No additional charge</td></tr>
<tr><td>Vulnerable/ Fuel Poor Domestic</td><td>No additional charge</td></tr>
</table>

Option development

Options development

> By the next meeting we need two deliverables for each option area (structure of charges, locations and temporal signals, whole system charges):

1. A draft of the section of the initial options document for that option area, to be discussed at the next TF meeting and published end January. Each section should set out:
   - A description of how the different options within that area could work
   - A discussion of how the different options would apply to different types of network user
   - A description of what links to other option areas have been identified

2. Slides to set up a discussion at the next TF meeting on the merits of the different options. These should cover:

- An initial assessment of advantages and disadvantages of each option.
- The key challenges/opportunities/enablers associated each option.

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TF member allocations

- Propose that we have three groups to deliver both 1. and 2. for each option area. We would like one or two leads for each, with others supporting by providing input and challenge to draft materials.

Option area	1. Lead on options report	2. Lead on initial assessment slides	3. Supporting group
Structure of charges			
Locational and temporal signals			
Whole system charging			

- Leads should send their outputs to the Secretariat/Ofgem by 16 January for circulation to the TF on the 18 January. Ofgem are also happy to engage in discussions as materials are developed.

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Options discussion today

- In the next three sessions we will be discussing the initial thinking on the different options.
- We think the key questions to discuss are:
  - Are there further options that have not been identified?
  - How do the options relate to different network users needs?
  - What are the key questions/uncertainties about how they would work that we need to develop a better view on?
- At the end of each session we will look to allocate members to the next round of work as per the table in the previous page.

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Lunch

Structure of charges– option development

Tariff Structures Summary

> These slides aim to:
  > Summarise the current position in respect of Distribution Use of System (DUoS) charging structures
  > Summarise the current position in respect of Transmission Network Use of System (TNUoS) charging structures
  > Give a brief overview of changes which could be considered

DUoS - Summary

- Two different methodologies are used to determine UoS charges for distribution connected demand and generation:
  - Common Distribution Charging Methodology (CDCM) applies to ‘designated LV’ and ‘designated HV’ customers, being all customers connected at less than 22kV where the metering is not at an EHV/HV substation
  - EHV Distribution Charging Methodology (EDCM) applies to ‘designated EHV’ customers, being all customers connected at more than 22kV, and customers connected at between 1kV and 22kV where the metering is at an EHV/HV substation

DUoS – CDCM Demand

> Each DNO uses DNO specific inputs to the CDCM model resulting in average tariffs by customer group which apply to all customers who fit the description of that customer group in that DNO area

Group	Customer Count (000s)	Proportion of Customers	Annual Reveune (£m)	Proportion of Revenues
Single rate NHH domestic and small non-domestic	24,659.3	82.0%	2,586.8	49.2%
Multi-rate NHH domestic and small non-domestic	5,115.7	17.0%	610.0	11.6%
HH domestic and small non-domestic	77.3	0.3%	115.6	2.2%
CT metered customers (HH settled in MC C and E)	193.4	0.6%	1,861.4	35.4%
NHH Unmetered supplies	28.8	0.1%	21.8	0.4%
HH Unmetered supplies	0.4	0.0%	64.4	1.2%
Total	30,074.9	100.0%	5,260.1	100.0%

DUoS – CDCM Demand

- There are five tariff elements used:
  - Unit rates; some customer groups have a single unit rate which applies to all consumption whilst some have unit rates which vary by time of day
  - Fixed charges
  - Agreed capacity charges; only HH settled customers with CT metering have an agreed capacity charge
  - Excess capacity charges; for any capacity used in excess of agreed capacity, and charged for the full month in which any breach occurs
  - Reactive power charges; only applicable when the power factor of the site falls below 0.95

DUoS – CDCM Demand

> Revenue by tariff element:

Group	Unit Rate 1 Revenue (£m)	Unit Rate 2 Revenue (£m)	Unit Rate 3 Revenue (£m)	Fixed Charge Revenue (£m)	Capacity Charge Revenue (£m)	Reactive Power Charge Revenue (£m)
Single rate NHH domestic and small non-domestic	2,194.8 84.8%	-	-	392.0 15.2%	-	-
Multi-rate NHH domestic and small non-domestic	519.5 85.2%	17.5 2.9%	-	73.0 12.0%	-	-
HH domestic and small non-domestic	88.7 76.7%	22.6 19.6%	2.7 2.3%	1.6 1.4%	-	-
CT metered customers (HH settled in MC C and E)	942.5 50.6%	208.5 11.2%	26.1 1.4%	16.5 0.9%	641.3 34.5%	26.5 1.4%
NHH Unmetered supplies	21.8 100.0%	-	-	-	-	-
HH Unmetered supplies	44.1 68.5%	6.7 10.4%	13.6 21.1%	-	-	-
Total	3,815.4 72.5%	255.7 4.9%	42.4 0.8%	483.4 9.2%	641.7 12.2%	26.5 0.5%

DUoS – CDCM Generation

- Each DNO uses DNO specific inputs to the CDCM model resulting in average tariffs by customer group which apply to all customers who fit the description of that customer group in that DNO area
- Credits are awarded to generators for offsetting network reinforcement at higher network levels

Group	Customer Count (000s)	Proportion of Customers	Annual Reveune (£m)	Proportion of Revenues
NHH generation	3.4	31.9%	- 0.2	0.4%
HH intermittent generation	5.8	54.2%	- 24.4	44.4%
HH non-intermittent generation	1.5	13.9%	- 30.3	55.2%
Total	10.6		- 55.0	

DUoS – CDCM Generation

- There are three tariff elements used:
  - Unit rate credits; NHH settled and HH settled intermittent generators have a single unit rate which applies to all consumption, HH settled non-intermittent generators have unit rates which vary by time of day
  - Fixed charges
  - Reactive power charges; only applicable when the power factor of the site falls below 0.95

DUoS – CDCM Generation

> Revenue by tariff element:

Group	Unit Rate 1 Revenue (£m)	Unit Rate 2 Revenue (£m)	Unit Rate 3 Revenue (£m)	Fixed Charge Revenue (£m)
NHH generation	0.2	-	-	-
HH intermittent generation	25.0	-	-	0.5
HH non-intermittent generation	21.4	7.6	1.7	0.3
Total	46.5	7.6	1.7	0.8

DUoS – EDCM Demand

- Each DNO uses site specific inputs to the EDCM model for each customer resulting in a unique tariff for each customer
- There are four tariff elements used in demand tariffs calculated in the EDCM:
  - A seasonal time of day unit rate applied to consumption within the DNO-specific ‘super-red’ timeband
  - Fixed charges
  - Agreed capacity charges for agreed import capacity
  - Excess capacity charges for any capacity used in excess of agreed capacity, and charged for the full month in which any breach occurs

DUoS – EDCM Generation

- There are four tariff elements used in generation tariffs calculated in the EDCM:
  - A seasonal time of day unit credit applied to consumption within the DNO-specific ‘super-red’ timeband and only to generators who are deemed to support the network
  - Fixed charges
  - Agreed capacity charges for agreed export capacity
  - Excess capacity charges for any capacity used in excess of agreed capacity, and charged for the full month in which any breach occurs

Revenue Proportion	Unit Rates	Fixed Charges	Capacity Charges
EDCM	1.7%	12.0%	86.3%

TNUoS – HH Demand (T+D)

> Applies to all transmission connected demand, and all CT metered HH settled distribution connected demand

> Charged according to the average demand (kW) they take over the three 'Triad' periods each year, on the basis of a £/kW tariff

> Triads are defined as three half-hour settlement periods with highest system demand between November and February, separated by at least ten clear days

> There is a locational element to the charge (across 14 demand zones) plus a residual element to ensure cost recovery

TNUoS – NHH Demand (D only)

- Applies to NHH and all WC metered HH settled demand (all distribution connected)
- Charged according to the sum of their annual consumption between 4 and 7pm (kWh) on the basis of a p/kWh tariff
- There is a locational element to the charge (across 14 demand zones) plus a residual element to ensure cost recovery

TNUoS – Generation < 100MW

- Applies to distribution connected generation below 100MW
- Suppliers are charged for their net demand, e.g. a supplier with 8MW of demand and 5MW of generation can ‘net off’ 5MW and so only be liable for their net position, being the remaining 3MW
- In effect, distribution connected generation below 100MW receive credits which are the exact inverse of the demand charge in that demand zone
- CMP 264 and 265 will result in the credit available to distribution connected generation below 100MW being only the inverse of the locational element (i.e. excluding the residual element)

TNUoS – Generation > 100MW

- Applies to transmission connected generation above 100MW
- Pay on a £/kW basis in respect of their Transmission Entry Capacity (TEC), with a site specific £/kW rate calculated annually
- There are three elements to the £/kW charge:
  - a 'wider' locational element to the charge which varies across 27 generation charging zones
  - a 'local circuit' and/or 'local substation' charge reflecting the cost of assets between the generator and their nearest Main Interconnected Transmission System node
  - a residual element to ensure cost recovery

Options within existing structure

- Balance between fixed and variable charging elements – this debate may need to take direction from the Access Task Force, given a level of capacity charging may already be being undertaken to reflect that the customer is ‘buying’ a network access product
- The relevance of reactive power charges, where the level of capacity a customer requires is already impacted by reactive power usage
- The use of variable unit rates, reflecting the differing pressures exerted on the system from usage at peak time compared to off peak periods, along with the possibility of tariffs which vary seasonally

Fundamental change options

- Wider use of capacity charging, where at present explicit DUoS capacity charges are levied only on CT metered HH settled customers
- Time of day or seasonal time of day capacity charging
- Charges for gross demand, where at present all charges are levied on a net demand basis
- Should charging structures for DUoS and TNUoS align, or are the different structures appropriate due to the different costs each end user imposes on the transmission and distribution networks respectively

Volunteers

Option area	1. Lead on options report	2. Lead on initial assessment slides	3. Supporting group
Tariff structure			
Locational charging			
Whole system charging			

Better locational charging – option development

Provisional Views.

The presentation attempts to provide an initial view of locational charges.

Whilst it endeavours to coordinate the views of contributions received, it is acknowledged that stakeholders from different parts of the energy community are likely to have different (and diverse) views of what locational charges are and on how and to who they should be levied.

Therefore the presentation is provided as an initial starting point to stimulate debate.

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What are locational costs

- Assumption is that network costs differ by location.
- Suggested working definition:

  Locational costs are the costs that are specific to the construction, owning and operating of a network in a specific geographic area. locational costs exclude the common costs of operating the business; e.g. IT systems, call centres, corporate functions such as finance and policy.

- The range of how locational costs are recovered can vary from:
  - socialising them across all customers and recovering them as an "average"; to
  - making them specific to each individual customer.
- Common costs are not locational; therefore questionable whether:
  - common costs should be allocated to consumers on the basis of location; or
  - recovered as a separate component of a customers charge; i.e. with no locational signal.

What drives locational costs

- Network costs that are locationally specific:
  - Costs incurred in providing new connection assets.
  - Sunk 'investment' costs in associate with providing the local network.
  - The future cost of providing the network (e.g. new connections, reinforcement, replacement).
  - The 'total' local cost of operating the network (maintenance, repair, losses).
- Characteristics that drive locational costs include:
  - Topography of where network is provided.
  - Customer density, and mix.
  - Network usage including local load and generation offset each other.
  - Network design, age and utilisation of the network.
- How can/should costs be quantified?
  - On an absolute or relative cost basis?
  - £/ metre (cable?); £/kVA (substations?.
  - Should on-costs be included? If so, on what basis?

Locational costs can be temporal

- Customer demographics vary over time.
  - New customers may require/ drive new network infrastructure and reinforcement.
  - The moving away of customers may result in network “redundancy”.
  - Change in customer mix.
  - the move to PVs, Evs changing peak demand and load factor driving or removing the need for generation.
  - Generation moving from intermittent to non-intermittent.

- Design standards:
  - “Environmental” requirements (e.g. undergrounding, flood risk).
  - Changes to design standards (e.g. system security).

- The way networks have been provided and funded over time can give different new investment on new methodologies (differential treatments on socialising).
  - What time period should be used for forward looking costs?

Why locational pricing?

- To reflect the costs that users bring to the network at different locations.
- To give a “long term” pricing signal that drives efficient use of the **total system**?
  - Providing and maintaining assets is a long term investment.
  - Locational prices should reduce total system cost (transmission and distribution)? – not just move costs from one location to another.
- To incentivise where load, generation and support services connect?
  - load, generation and support service to relocate to the “*right*” locations?
- Is there a place for short term locational pricing?
  - Short term pricing signals can give volatile and confusing signals.
  - What costs would short term pricing relate to?

Locational prices today - Connections - Distribution

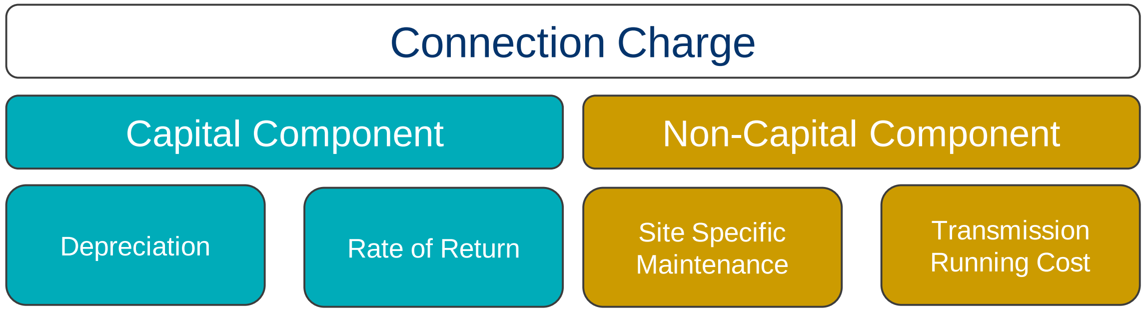
- CCCM common across all DNOs:
  - Applies to customers connected at all voltage levels on distribution system.
  - Charges for demand and generation treated on the same basis.
  - CCCM is not directly linked the to CDCM/ EDCM; i.e. changes to one don't automatically mean changes to the other.
- Connection charges are "shallowish":
  - Costs at more than one voltage level above the connection voltage are socialised and recovered through DUoS.
  - Where assets are "shared" they are apportioned between "new customer" and existing network customers.
  - Shallowish costs reduce locational signal.
- Charges may contain capitalised operation and maintenance:
  - Speculative connections/ capacity.
  - Capitalised O & M could be local.

Locational prices today – Use of System - Distribution

- Market assumption is that all electricity is conveyed to and from the GSP:
  - No peer to peer or 'local' tariffs.
- EHV customers subject to EDCM (either FCP or LRIC).
  - Both FCP and LRIC provide locational signals.
  - LRIC more locationally granular than FCP.
  - Charges based on capacity headroom and modelled time to reinforcement for the relevant node or group of nodes – based on demand forecasts.
- HV and LV customers subject to CDCM.
  - CDCM charges do not provide locational pricing signals
  - Tariffs are average charges for each GSP group.
- Restrictions under the section 3A (3)(d) of Electricity Act:
  - Ofgem Government have duty to "have regards to the interests…of individuals residing in rural areas".

Locational prices today – Connection - Transmission

- “Assets installed solely for and only capable of use by an individual User”
- Due to the location of the ownership boundary at the substation, generators do not generally pay connection charges



Locational prices today - Use of System - Transmission

- Locational signals created through DCLF model for incremental cost related pricing – the Transport Model.
- The National Electricity System must confirm to the Security Standard (deterministic and cost benefit analysis aspects) this obligation provides the underlying rationale for the ICRP approach.
- The charging methodology reflects this through the use of dual backgrounds in the Transport Model.
- Model quantifies the relative cost differences between different zones based on an 'distributed' reference node. No attempt to price the absolute costs.

> For Generation:
  - Generators may pay local substation and circuit charges depending on location.
  - The average generation charge must be within a range of 0-2.50€/MWh

> For Demand:
  - Demand charges are paid on HH and NHH tariffs.
  - HH demand charged on the 'triad'.
  - NHH demand charged 1600 – 1900 hours all year round.
  - Distributed generators receive a £3.22 Avoided GSP Infrastructure Credit (AGIC), which is the average annuitized cost of infrastructure reinforcement works at GSPs, divided by the capacity at those GSPs.

TNUoS Charges

energynetworks association

Locational Element: Transport Model

- Circuit Data
- Demand Data
- Generation Data
- Expansion Factors / Zones

The Transport Model

- Step 1: Base Case Cost Calculation
- Step 2: Incremental Cost Calculation

Outputs

- Nodal Incremental Costs

= Locational Tariffs

Residual Element: Tariff Model (Revenue recovery)

- Allowed Revenues & G/D split
- Forecast of Gen
- Forecast of Demand

= Residual Tariffs

Concerns with locational pricing

- Do locational pricing signals work?
- To what extent should locational prices reflect absolute locational costs.
- Differences between the way locational costs are priced in transmission, distribution EHV and distribution sub EHV creates competitive distortion for different tiers of connection (i.e. should locational costs be recovered through connection costs or usage charges?)
- Changes in charging methodologies over time has created distortion in the locational pricing messages.
  - This can distort the costs of new technologies over older technologies.
- Should locational charges give other signals other than reflecting the costs.
- Charging methodologies (for distribution) are based on demand models
- How can locational signals incentivise/ recognise integration of demand

Complexity and stability of Tariffs

- Increase in locational tariffs likely to result in increased modelling complexity
  - Reduces modelling transparency?
  - Is forecast reinforcement the right approach to model locational charges?
- Locational tariffs subject to more short term (year on year) volatility.
  - Do network total costs change significantly year on year.
  - Should we have a rolling average of a long term period to avoid large swings?
  - Short term pricing signals will give confusing messages to long term investment.
- Should locational charges recognise the ability to balance locally:
  - A single 'users charge' for generation and demand connected close together?
  - At present generators are 'blamed' for reverse power flow but this could be regarded as demand not using power at the right time.
- At present charges are bundled up for small users with no transparency via the supplier.
  - This could continue or the charges listed depending on behaviour. This would give choice but also protect those who want a fixed fee.
- Future customers connecting, or changes to an existing customer's use, may drive changes to other users' locational costs; e.g.
  - increase in CDCM demand at a node impacts on EDCM customers' charges)

Future locational pricing

- Should locational prices reflect the absolute or relative locational costs?
  - What is the difference?
- Should locational charges be given through deeper connection charges:
  - Costs are known at time of investment decision.
  - Common principles required across distribution and transmission.
  - Would increase competitive distortions between DG and TG
- What pricing signals should locational charges give?
- How should locational signals be given through use of system charges:
  - Should average tariffs be replaced with zonal/ nodal tariffs.
- Locational tariffs may be more volatile and unpredictable
  - Future customers connecting, or changes to an existing customer's use may drive changes to other users' locational costs.
  - Tariffs could be introduced as ex-ante or ex-post.
- To what extent should locational signals reflect
  - Operational conditions.
  - Network planning standards.
  - Power flows.
  - spare capacity.

Future locational pricing - Distribution

- How should the EDCM and CDCM evolve to align with Transmission charging methodologies (and vice versa).
  - Connections at 132kV in Scotland receive different treatment than in England and wales – is this right?

> Should EDCM and CDCM merge to become single methodology
  - Should there be different methodologies at different voltage levels
  - Should average tariffs (the CDCM) be replaced with zonal/ nodal tariffs.
  - Are different tariff structures required for different size/ class of customer?
  - EDCM does not automatically recognise value of avoided infrastructure reinforcement, avoided direct and indirect costs and network rates.

- Should locational components be linked to STOD.
- How should locational reflect local balancing - both load and generators need to benefit?
- Tariffs need to reflect inter system as well as intra system costs

Future pricing of locational costs – Transmission

- Through deeper connection charges:
  - Costs are known at time of investment decision.
  - Fixed upfront charge or over the lifetime of asset.
  - Increased security required from users.
- Through use of system charges:
  - Increasing tariff types for demand – new capacity and usage charges?
  - Increasing the absolute value recovered from locational charges (through increased locational costs or change reference node location).
  - Changing charging base for demand e.g. removal or change to triad for HH tariffs.
  - Increasing granularity of tariffs to smaller zones or nodes
  - Locational variability for system operation costs recovered within BSUoS.
  - Tariffs could be introduced as ex-ante or ex-post.
- Is the link with the security standard required to be maintained?
  - Locational charges are closely related to security standards. Do these standards need to be system wide?
- Do we need a better assessment of the cost benefits of distributed generation beyond what is currently captured in the Avoided GSP Infrastructure Credit (AGIC)?
  - AGIC does not include the cost of Super Grid Transformers or avoided RIIO payments to Transmission Operators.

Volunteers

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Whole system charging			

Whole system charging

Whole system costs

- Users impose costs throughout the system and not just to the part of the network to which they connect.
- Users should face charges which reflect these whole system costs.

Existing examples of whole system options

- Distribution-connected users pay TNUoS and BSUoS charges.
- HV and LV distribution users pay for the cost of the EHV distribution assets, as these assets are taken into account via CDCM UoS methodology.

Gaps in existing whole system

- Distribution-connected generators do not face charges for the costs that they create on the transmission network if the GSP is exporting onto the transmission network.

Two fundamental options

- Including all costs and users face a **single network charge**
- Exposing users to **an additional charge** to take account of costs from different parts of the system

Charging Futures

Options for charging distribution-connected generation for transmission costs

Supplier or DNO led charging

- Should any charges from distribution-connected generation for transmission costs should be recovered via suppliers or via DNOs.

The structure of charges

- Should any charges be based on gross generation export or net export?
- Even within "Net Exports" there are different options:
  - Costs could be charged out to all DG based on connection voltage.
  - Cost could be charged out to the DG that contribute to the export.
- Should charges be based on an absolute or relative basis?

Links to Access Products

- Could some of these models lead to the creation to the 'DTEC'?

Charging Futures

Questions to consider

Singe network charge – point to consider

> Is it possible to accurately represent the entire network within a single model?
> Could any of the existing models be expanded to cover the entire network?
> What are the current barriers to a single network charge?

An additional charge – points to consider

> What costs should this charge recover?
> Who would issue this charge?
> What would the basis the charge be?
> What level of locational and temporal granularity would be appropriate?
> What would the impact of this be on the development of access products?

Are there other options?

Charging Futures

Volunteers

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Charging Futures

Meeting wrap up