Network charging for a flexible future

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Written by:	Keith Gillanders, Johnny Gowdy, Merlin Hyman and Tamar Bourne
Approved by:	Merlin Hyman

Regen SW, The Innovation Centre, Rennes Drive, Exeter, EX4 4RN
T +44 (0)1392 494399 F +44 (0)1392 420111 E admin@regensw.co.uk www.regensw.co.uk

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Executive Summary

The UK electricity system is rapidly changing. Following a radical increase in the amount of renewable generation, we are now seeing the growth of smart technology and services that can enable more flexibility in the way we generate, supply and use power. The National Infrastructure Commission has responded to these changes by calling on the UK to lead the world in a “smart power revolution”.

The grid charging regime has a key role to play in encouraging the most efficient use of the networks; to enable the decarbonisation of the power system and continued security of supply at the lowest cost.

The primary function of the grid charging regime is to recover costs in a way that is cost reflective and to ensure fair competition in the generation, distribution and supply markets. In addition to this function, the charging mechanism also has an important role to play in sending forward price signals that will guide future investment in transmission and generation assets, and will influence their location, choice of technology and operation. During a period of rapid change, modifications to network charging could have a significant influence over the development of innovative technology and new business models that could deliver greater system flexibility and decarbonisation.

There is general agreement that the current charging regime is no longer fit for purpose. For some time the complexity of the charging regime and the distortions it has introduced to the market have been tolerated for the sake of continuity.

While Regen agrees that the charging regime needs to be overhauled, Ofgem’s proposed intervention on embedded benefits raises the risk that a short-term fix, dealing with only one aspect of the charging regime, will introduce further distortion. Critically it may curtail investment in new and innovative technologies and business models such as energy storage, demand side response and local energy supply markets.

Moreover, there is concern that such an approach may miss the opportunity to carry out a more thorough review that would provide a long term framework for future grid and generation investment, which could exceed £200 billion[1] over the next ten years.

Given the importance of the getting the charging regime right and sustainable in the longer term, we are strongly urging UK government, Ofgem and National Grid to work closely with industry and to conduct a more thorough review of charging.

Designing a charging regime for the network to send the right signals to market participants to achieve government goals for

[1] National Grid http://www2.nationalgrid.com/UK/Our-company/RIIO/

the electricity system, is a challenging and complex task. We propose that any review of network charging should be underpinned by the following principles:

- Cost reflective and support competition
- Incentivise long term reductions in network costs
- Ensure that grid charging is aligned with other energy policies to meet the UK governments long term decarbonisation and energy security objectives
- Support innovation and the development of new technologies and competitive business models
- Encourage network balancing by strengthening the appropriate locational and temporal signals while retaining, as far as possible, the principle that charging reflects the true cost of the network
- Ensure the charging regime is transparent and charges are visible to all customers
- Changes are made in open consultation with all stakeholders and not subject to vested interest
- A holistic approach is taken, specifically any review should:
    - Consider the full scope of all grid charging mechanisms at both a transmission and distribution network level and how they interact
    - Strike an appropriate balance between charges levied on generation and those on demand
    - Support increased integration via interconnection with European energy networks and the need to harmonise grid charging to facilitate this.

Introduction

It is difficult to exaggerate the speed and scale of the changes in our electricity system. Renewable energy now accounts for over 25 per cent of our power from nearly one million renewable generators across the country.

However, this is just the start. The UK has committed to developing a smart and flexible power system, as set out in the National Infrastructure Commission Smart Power report.[2] The Department for Business Energy and Industrial Strategy (BEIS), supported by Ofgem, will issue a consultation on how to take forward the conclusions of the Smart Power report. This will give the new department its first opportunity to set out a clear strategy for the UK's future low carbon energy system, backed by a coherent industrial strategy.

One critical factor which will influence how our electricity system develops over the coming years, is the way we charge for the use of the network. The charging regime already sends key signals to the market, including those which influence where and when power is produced and consumed. Importantly BEIS has said that network charging will be one of the elements of the smart power consultation.

Ofgem has already published an open letter, 'Charging arrangements for embedded generation', indicating that it is urgently considering changes to the current network charging regime.[3] The letter, which was written in response to BEIS concerns about whether the level of embedded benefits favour distributed generation over transmission connected generation, calls on industry to engage in consultation and to make its own recommendations on future network charging.

The purpose of this paper is to consider what the principles of a future network charging regime should be, in order to create a regime that is fair to network users, but also supports the transition to a smart and more flexible energy system. It is hoped this paper will contribute to the Smart Power consultation, wider discussions on the value of flexibility and shorter term proposals on embedded benefits.

Our approach is to set out the direction of travel for the electricity system, the current charging regime and the reasons why there is a need for change. We then propose principles for reviewing charging in a rapidly changing system.

[2] National Infrastructure Commission, 2015, *Smart Power*

[3] Ofgem, July 2016, Open letter: Charging arrangements for embedded generation

A changing energy system

A flexible electricity system

A changing system

During the last decade there has been a radical shift in our electricity system. From a system primarily based on around 50 large generators connected to the transmission network, we are now approaching one million generators, the vast majority of which are connected to the local distribution network. Renewable energy contributed almost 25 percent of our power in 2015[4] and this has continued to grow as projects in the pipeline are completed.

Direction of travel

In the 2015 Paris Agreement, the international community agreed to hold the increase in temperature to well below 2^{o}C and to pursue efforts to limit the temperature increase to 1.5^{o}C. To contribute to this effort, by 2030, electricity generation in the UK must achieve CO_2 emissions of 50 to 100g/kWh overall, compared to 410 g/kWh now, and by 2050 electricity generation must be largely decarbonised.[5] The decarbonisation of the heat and transport sectors means that, despite energy efficiency measures, demand for electricity is expected to rise by approximately 15 per cent by 2040.[6]

The UK government has stated that all new policies for investment and reform must address the 'energy trilemma' – the challenge of keeping the lights on, at an affordable price, while decarbonising the power system. The government has also committed to developing a smart and flexible power system.

A future energy system

There are several sources of analysis on future energy scenarios including those produced by the National Grid[7] and the Committee on Climate Change[8]. For the purposes of this paper, it is considered that a future decarbonised electricity system is likely to have the following physical features:

- installed capacity of variable generation, principally wind and solar PV, in the range of 60 to 80% of total capacity
- a component of nuclear generation and/or fossil generation with carbon capture and storage to provide peaking capacity and system services
- smart technology on transmission and distribution networks, as well as generation

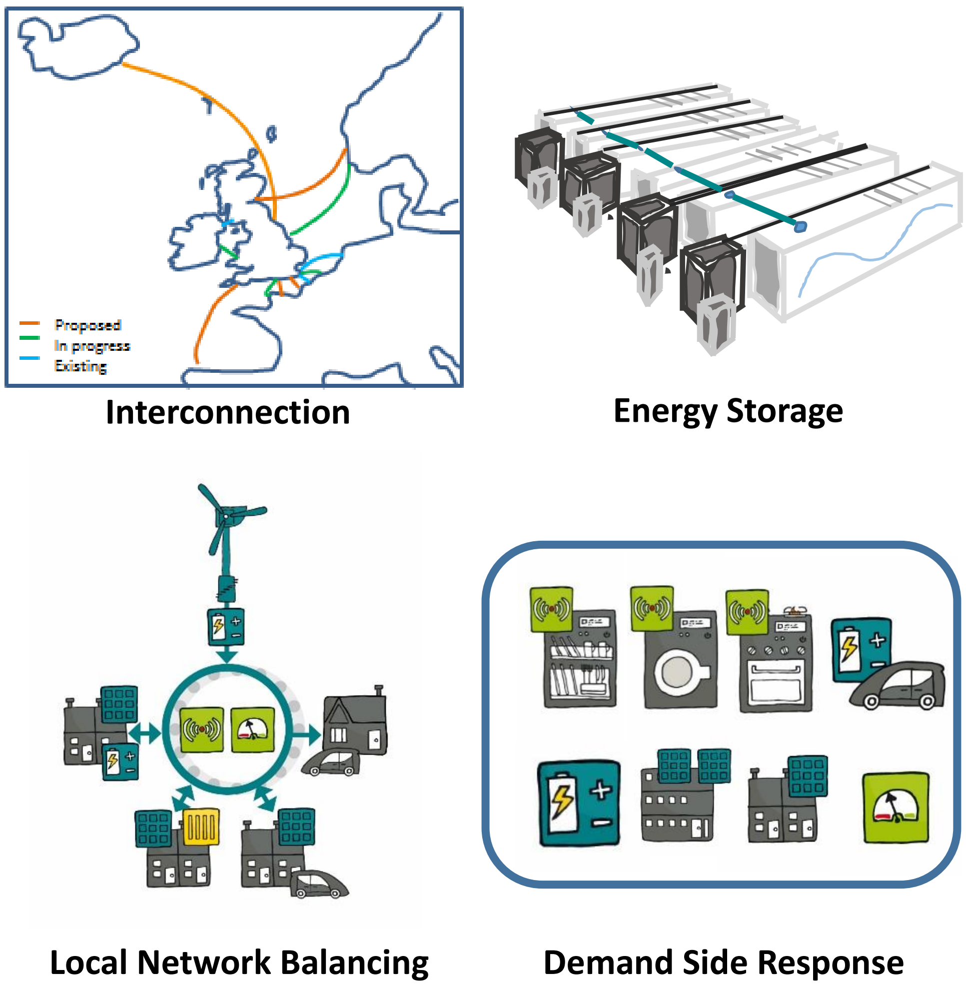
[4] BEIS, 2016, Digest of United Kingdom Energy Statistics (DUKES)
[5] Committee on Climate Change, 2015, *Power sector scenarios for the fifth carbon budget*.
[6] National Grid Future Energy Scenarios 2016
[7] National Grid Future Energy Scenarios 2016
[8] Committee on Climate Change – Sectoral Scenarios for the 5th Carbon Budget

- network connected energy storage systems that will be used in a variety of modes from near-instantaneous response services, to larger scale energy reserve storage
- electric vehicles and electric heating, for example using heat pumps where usage is controlled as part of demand side response; the batteries in electric vehicles may be used as flexible load and reserve storage for the system
- a large interconnection capacity to other countries.

The future electricity system will also see changes in operational aspects, including for example:

- a large component of demand side response to allow some percentage of demand to be shifted from peak time to another time of day
- real time pricing to allow demand and generators to respond to local network conditions
- local balancing so that, as far as possible, generation within a locality equals demand
- DNOs becoming Distribution System Operators (DSOs) with a more active role in local balancing
- micro-grids operating independently of the main distribution network
- reducing the uncertainty of wind and solar generation through improved forecasting
- new methods of supplying system services such as voltage and frequency control.

Figure: New sources of flexibility



The key role of flexibility

The National Infrastructure Commission concluded that a flexible smart power system will support low carbon savings of up to £8.1 billion a year by 2030 and is a 'low-regret' option against business-as-usual, with limited operational flexibility.[9] Low-regret means that when high levels of flexibility are designed into the system, the outcomes are resilient and low-cost for a range of generation scenarios when new technologies such as energy storage and carbon capture are implemented.

The studies[10] underpinning the National Infrastructure Commission estimate, are based on achieving carbon emissions of 50 to 100 g/kWh with security of supply at an optimal cost. The key findings are:

- Flexibility could enable up to 80 per cent of electricity capacity to come from variable renewables
- The gross benefits of flexibility increase, the more decarbonised the system is:
  - 50 g/kWh between £7.1 - 8.1bn/year
  - 100 g/kWh between £3.0 - 3.8bn/year
  - 200 g/kWh around £2.9bn/year
- These flexibility options exist today or are likely to be available by 2030, but may not be sufficiently incentivised by the current market arrangements
- Provided that sufficient flexibility and reserve/response is available, the system can cope at times of stress (e.g. lots of wind, very low wind over several days, unexpected nuclear outages, low fuel prices, high demand) and achieve the carbon target.

[9] National Infrastructure Commission, 2015, *Smart Power.*

[10] Imperial College, 2015, *Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies* and Nera 2015, *System Integration Costs for Alternative Low Carbon Generation Technologies – Policy Implications*

The current charging regime

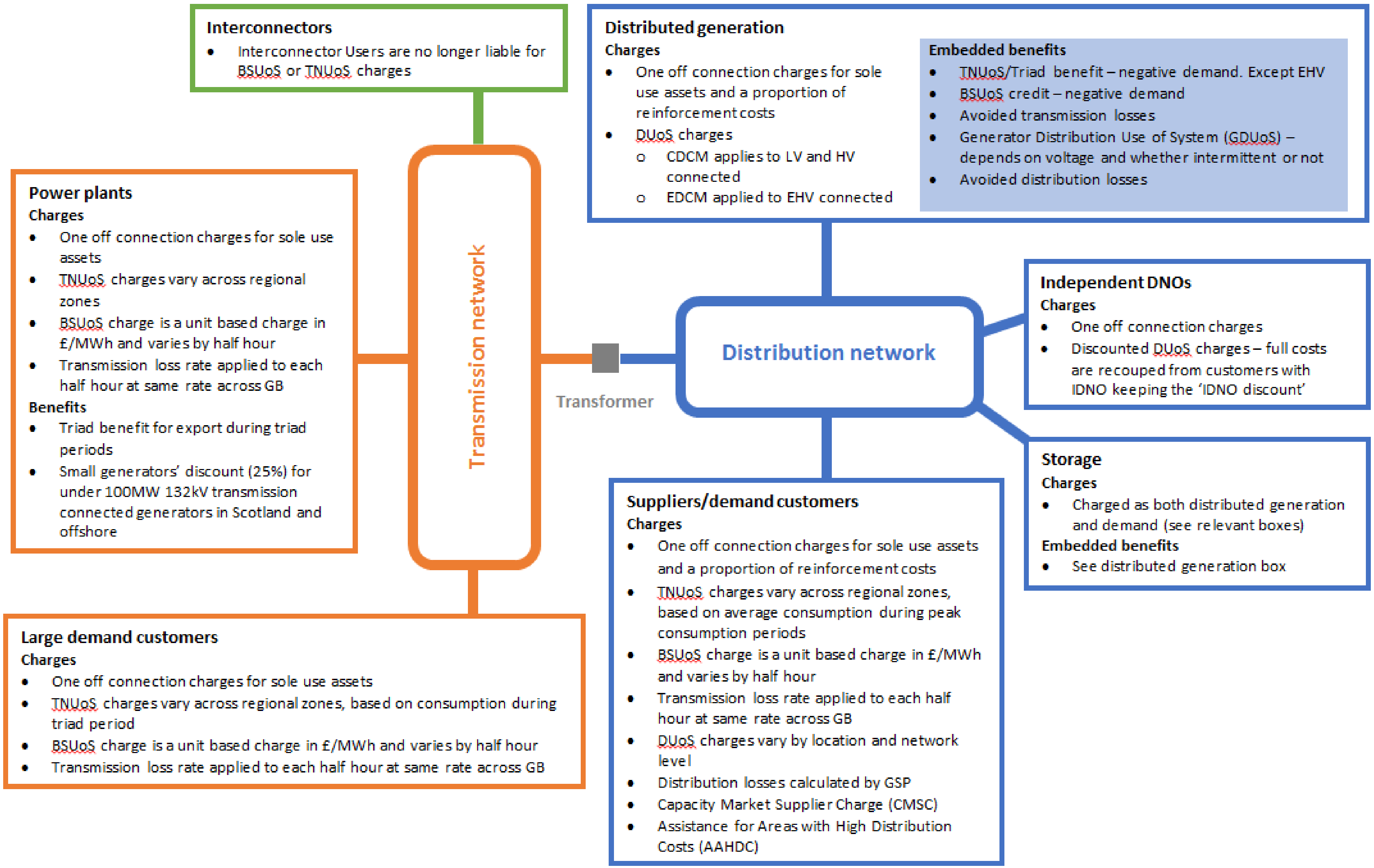
Overview of current charging regime

The charging regime for the network has a key role in the electricity market. The charges provide critical signals as to the type of generation, its location and what times it generates. Charges also influence where and when demand is located. Innovations such as demand side response and storage technologies are influenced by the market signals sent by the charging regime.

Network charging methodologies are determined by codes and agreements, such as the Distribution Connection and Use of System Agreement (DCUSA) and Connection and Use of System Code (CUSC). Ofgem approves the codes and agreements and sets price controls for the companies that operate the electricity networks. Price controls set the amount of money (Allowed Revenue) that can be earned by the network companies over an eight year period. The Allowed Revenues are recovered from their unit and demand charges to suppliers, who in turn pass these costs through to customers.

There are charges for use of the transmission system, the distribution system and for balancing services. The following figure summarises which charges apply to different network customers. More details are given in an appendix.

Figure: Transmission and distribution connected stakeholders and list of charges and credits applicable to each



Challenges for the charging regime

There is general agreement that the current network charging regime is not fit for purpose and needs to be reformed. In July 2016 Ofgem published an open letter on 'Charging arrangements for embedded generation'. The letter, in response to BEIS concerns about whether the level of embedded benefits favour distributed generation over transmission connected generation, sets out a number of issues within the charging regime which Ofgem consider to be of sufficient concern to warrant intervention.

This section sets out some of the current issues under debate.

Charging based on peak demand (Triads) has become distorted

It is common in energy systems for network charges to be split between generators of energy and demand customers. The cost weighting is usually towards demand,[11] and in the UK, demand pays for over 80 percent[12] of the transmission network costs and is expected to pay for over 90 percent of costs by 2020/21 if the UK maintains the current EU generation cost cap of €2.50 per MW/h generated.

The way that demand pays for the network could be based on a number of elements:

- **Peak demand** – per kW at peak - charges based on times of peak usage, on the basis that it is peak demand that drives the overall investment in the grid and the marginal cost of its operation
- **Usage demand** – per kWh usage - charges based on customer energy usage, on the basis that usage of the grid drives its operation and maintenance, wear and tear and the depreciation of existing assets
- **Fixed cost** – per customer – a charge based on the fact that every demand customer needs the grid no matter how low their usage and that there is a fixed element to provide this service.

There has been much debate about which of these demand elements should be allocated the most cost and different models have been used around the world. The Brattle Group carried out an international survey of distribution tariff design options and identified four broad ways in which tariffs are being restructured:[13]

1. Higher standing charge
2. Peak demand charge

[11] Cornwall Energy – A review of Embedded Benefits Accruing to Distributed Generation in GB Appendix B - International Models of Transmission Charging Arrangements
[12] National Grid Forecast TNUos Tariffs from 2017/18 to 2020/21

[13] The Brattle Group, The Tariff Transition: Considerations for domestic distribution tariff redesign in GB, April 2016

3. Time-varying unit charges
4. Inclining block rates

In the UK the weighting has been very much towards net peak demand. For higher energy users (half hour billed), the main grid Transmission Network Use of Service (TNUoS) charge is based wholly on kW net peak demand calculated on the three highest annual demand events (Triads).

The charging regime should encourage demand reduction at times of peak demand, as this has the effect to reduce overall network and generation capacity requirements – and investment costs – and to maintain the capacity margin needed for energy security. In the past, peak demand was also an approximate indicator of overall demand and so the system was in the most, fair.

However, while demand side reduction is a positive response to grid charging, the operation of the Triad system, combined with the increased sophistication of predictive tools, has enabled energy suppliers and their high energy user customers, to effectively reduce their share of transmission charges. They can do this by reducing their **actual** demand during Triad periods, or their **net** demand by turning up distribution network connected (embedded) generation.

Hence distribution connected generation assets can earn significant revenue streams known as embedded benefits either by:

- directly saving network costs for high energy users behind the meter
- supplying energy onto the distribution network during Triad periods and earning embedded benefit payments via their Power Purchase Agreement (PPA) off-taker.

Along with an overall reduction in demand, an increase in embedded generation has contributed to a fall in the recorded Triad peak demand.

Since the full costs must still be recovered, this has effectively increased the cost allocation across other energy demand users that are less able to avoid the Triad related charges.

This is not a straightforward issue; reducing demand at times of peak is an overall benefit to the system and has helped to improve UK capacity margins and keep the lights on.

The problem is that the level of unfairness and distortion has increased because:-

- The sophistication to accurately predict when Triads will occur has greatly increased
- The value of embedded benefits/cost avoidance has also increased and is expected to rise from £45 per kW in

2016/17 to £50-80 kW by 2020/21 (depending on location)

- The opportunity to earn or save circa £45,000 per MW installed from embedded benefits has encouraged a massive increase in the deployment of generation assets, including small scale diesel and gas reciprocating generators.

Some commentators have talked of a 'death spiral of the grid'; as local generation and shifts in demand reduce network use, and therefore income for system operators, leading to higher prices for those that do use it, which in turn incentivises more local generation and lower demand.

The sunk costs must still be recovered and should be done in a way that is fair to all users. An alternative approach to using Triads needs to be put in place.

Transmission versus distribution connected generation

Ofgem's open letter of July 2016 raises concerns about whether the level of embedded benefits favour distributed generation over transmission connected generation.

Ofgem's main concern is that small distribution-connected generators are receiving increasing revenues from embedded benefits; that these arrangements are not fully cost reflective and therefore may over-reward distribution-connected generators.

Furthermore, the increasing levels of distributed generation are having an impact on flows from the distribution network onto the transmission network, which raises the issue of whether distributed generators should be contributing to the cost of the transmission network.[14]

Ofgem's focus on the embedded benefits attributed to transmission costs (TNUoS) and balancing services (BSuOS) have been critiqued for only looking at one part of the overall charging regime.

Cornwall Energy, a consultancy, commissioned by the Association of Decentralised Energy to review the embedded benefits accruing to distribution connected generation has taken a broader view. Their report found that while not perfect, the current level of embedded benefits captured by distributed generators fairly reward them for the costs that they avoid on behalf of network operators. While some benefits are overvalued at the transmission level, they are also undervalued at distribution level.[15] Therefore, a blunt reduction in transmission (TNUoS) embedded benefits without concurrent

[14] DECC, March 2016, *Consultation on further reforms to the Capacity Market*.
[15] Cornwall Energy for the Association of Decentralised Energy, May 2016, *Review of embedded benefits accruing to distribution connected generation in GB.*

increases in distribution benefits (DNUoS) would result in the embedded benefit regime becoming less cost reflective overall.

In addition, any changes in the value of the Triad charge must treat both demand response and distributed generation equally, or it risks sending different price signals for the same result – a unit of reduced demand on the transmission network.

Constraints on the distribution network

The distribution system was designed to take power from the transmission system to homes and businesses. As distribution connected generation has increased, the flow of power is now two way. Connection distributed generation has been impeded by constraints on the distribution networks. It is not possible to connect distributed generation in many areas of the country without expensive reinforcement works.

Charges for using the distribution system are not sophisticated enough to send signals to generators or demand customers to incentivise behaviour that reduces these constraints.

The transmission system has a system of payments to generators when they are constrained from generating, known as 'constraint payments'.[16] These payments provide a clear market signal to the system operator as to when investment would be cheaper than constraining generation. The lack of a similar system on the distribution network makes it harder to understand the cost of overcoming constraints.

[16] http://www2.nationalgrid.com/UK/Our-company/Electricity/Balancing-the-network/

Approaches to reform

While there is general agreement that the current charging regime is no longer fit for purpose, any changes to the charging system will have wide ranging impacts, which as well as creating winners and losers within the system, will also send strong signals to potential investors. These changes must be thought through carefully and should be part of a wider review of both the principles behind grid charging and the mechanism by which they are implemented.

A change to network charging rules must therefore consider:

- The impact on the bills of energy users– winners and losers
- Distortions in the generation markets, including the wider integrated European energy market
- The risk that capacity will be reduced or withdrawn from the market, impacting the UK's energy security
- Impact on investor confidence and certainty
- Risk that new technologies and business models will be curtailed

Ofgem's, open letter of July 2016, has flagged that the level of distortion and imperfection in the existing charging regime has now reached a critical point whereby the regime is no longer able to ensure cost reflective charging and fair competition, nor is it sending appropriate price signals to influence future investment.

While Regen agrees with the overall conclusion that the charging regime needs to be overhauled, Ofgem's intervention suggests a very narrow, approach looking at the distortion and cost effectiveness of transmission grid charging with a focus only on the Demand Residual element of TNUoS.

The letter also suggests that a very short term workaround solution, aimed mainly at ensuring there is a level playing field for transmission connected gas generation in the upcoming Capacity Market 2016 auction, may be the appropriate interim response.

This raises the real possibility that a short-term fix, dealing with only one aspect of the charging regime, will introduce further distortion and may curtail investment in new and innovative technologies and business models such as energy storage, demand side response and local energy supply markets.

The dangers of this short term approach are outlined in a blog by Nigel Cornwall, which concludes, "In the round we believe these impacts would create a significant net detriment to consumers through higher prices but lower security, especially in the near term" and that "there is a real risk of killing off flexibility markets before they have developed".[17]

Moreover Regen is concerned that such an approach may delay the opportunity to carry out a more holistic review of network charging that would provide a long term framework for future grid and generation investment, which could exceed £200 billion[18] over the next ten years.

Given the importance of the getting the charging regime right and sustainable in the longer term, we are strongly urging UK Government, Ofgem and National Grid to work closely with industry and to take a more holistic approach.

[17] www.cornwallenergy.com/Opinion/What-next-for-embedded-benefits-
[18] National Grid http://www2.nationalgrid.com/UK/Our-company/RIIO/

Principles for charging for a flexible system

Network charging for a flexible system

The government has committed to the UK developing a smarter electricity system with increasing flexibility through applications such as storage, DSR and dynamic tariffs. The signals sent by the network charging regime will be critical to how quickly and in what manner the system changes.

Designing a charging regime for the network to send the right signals to market participants to achieve government goals for the electricity system is a challenging and complex task.

A key challenge at a time of rapid change is that policy and regulation provide clarity and consistency, but are also sufficiently flexible to enable new technologies and business models to be trialled.

Proposed charging principles

In addition to the primary functions of being cost reflective and ensuring fair competition, the charging regime should:

- Align with wider government objectives
- Enable innovation
- Incentivise long term reductions in network costs
- Encourage local network balancing
- Be transparent with full stakeholder consultation
- Take a holistic approach.

For more detail, see the following sections.

Align with wider government objectives

Charging cannot be separate from other policy goals. It has the potential to encourage or discourage future investment decisions that could help meet the energy trilemma of keeping the lights on, at an affordable price, while decarbonising the power system.

Enable innovation

Ofgem has committed to developing a regulatory framework that enables innovation.[19]

The current rapid change in the electricity sector has altered the magnitude of costs and benefits and to whom they accrue. Most commentators expect this pace to accelerate due to the high rate of technological and social change.

Charging should provide clarity for market participants but also to allow for innovative tariffs to be tried with contract periods that are sufficiently long to allow innovators to make a financially feasible business cases.

A holistic review of the charging regime may take time and it is important that there is sufficient flexibility in the regulatory system that this does not prevent innovation. Mechanisms such as derogations for trials should be available and innovators should be able to get swift and transparent decisions from Ofgem on such mechanisms.

Incentivise long term reductions in network costs

There is a difference between what is cost reflective over the short term and long term. A longer term approach to cost recovery would allow time for price signals to take effect and could ultimately bring costs down. A clear direction of travel and longer term approach will also increase investor confidence.

Decentralised generation and storage have the potential to reduce network costs in the longer term if they are aligned with demand at a local level, as there will be less need to send electricity up and down the county. If network costs are treated as sunk costs and charged accordingly, that signal will be lost. Many of those costs are not, in fact, sunk over a longer time horizon.

Network charging should recognise that decentralised generation and storage reduces demand on the network in the longer term and, therefore, avoids network costs.

Encourage local network balancing

To enable a flexible network, that makes best use of increasing distributed generation and smarter communication technology, requires charging to become more sophisticated. The Rocky Mountain Institute (RMI) identifies three 'continuums' that they describe as "the what, when, and where of electricity generation and consumption":[20]

[19] See https://www.ofgem.gov.uk/publications-and-updates/ofgem-reviews-regulatory-framework-boost-innovation-and-enhance-consumer-protection

[20] RMI, August 2014, *Rate design for the distribution edge.*

- Attribute Continuum—the unbundling of charges to specifically price energy, capacity, ancillary services, etc.
- Temporal Continuum—moving from volumetric block charges, towards highly time-differentiated prices that vary in response to marginal prices or other market signals
- Locational Continuum—delivering price signals that more accurately reflect unique, site-specific value.

The RMI argues that breaking down charges into these distinct value streams is an important tool to direct investment decisions that optimise value to all customers as well as to the grid as a whole.

For example, consider the case of a distributed generator in the UK. Currently they have a strong locational and temporal price signal to sell power direct to a demand customer on the same site or through a private wire. This signal encourages the generation of power where and when it is needed. However, as soon as generation connects to the public network, that signal becomes much less clear. This leads to the current situation where areas like the south west of England are net exporters of power when solar irradiation is high, but importers at times of low irradiation.

Charging for generation should provide market signals to encourage power to be used as locally as possible. Current proposals to remove embedded benefits would be a step away from a strong locational element in charging.

However, charging cannot be purely locational. There will need to be recognition in charging that the distribution and transmission networks provide important services, such as backup, to which all generation and demand customers need to contribute. There is a strong argument that all users pay a fair amount for having access to the network, which does not need to be linked to how much they use.

The RMI propose increased charging sophistication along all three 'continuums'. For example, generators could receive real-time network price signals across all hours of the day, a strong locational element based on the kilometres of grid network used, value for ancillary services such as reactive power, and pay a charge for the backup services provided by the transmission network.

Be transparent

The charging regime should be transparent and charges visible to all customers. Some customers that are settled half hourly have access to information about their use of system charges which enables them to shift consumption to avoid the higher charges. This can help support network balancing if the price signals are clear.

As we move towards half hourly settlement for all, there is greater potential for all customers to engage in demand side response. The number of Non Traditional Business Models for supply coming forward suggests that customers will have greater choice of tariffs in the future. Transparency in the charging regime will be important for a wider range of market participants to respond to price signals.

Take a holistic approach

While charging needs to be sufficiently flexible to enable new technologies and business models to come forward, in general piecemeal changes should be avoided. Changes to charging should be made only following a review that is careful, holistic and systematic. There is a danger that a short-term response could cause significant harm to industrial manufacturers, a wide range of distributed generators and the development of a more flexible energy system.

The short term review of embedded benefits should, therefore, be integrated into a more holistic review of charging in the context of the government’s objectives for a smart, flexible energy system.

The charging framework review needs be holistic in the sense that it considers:

- The principles set out above
- The full scope of all grid charging mechanisms at both a transmission and distribution network level
- How to strike an appropriate balance between charges levied on generation and those on demand
- Support increased integration via interconnection with European energy networks and the need to harmonise grid charging to facilitate this.

Appendix: Network charging

Appendix: Summary of network charges and embedded benefits

This appendix sets out the key charging mechanisms for the operation of the networks, followed by a summary of embedded benefits.

Transmission Network Use of System (TNUoS) charges

TNUoS charges recover the cost of building, maintaining and operating shared electricity transmission assets. TNUoS charges are levied on all transmission connected generators, licensable embedded generators (greater than 100 MW), and suppliers of both half-hourly (HH) metered and non-half hourly (NHH) metered demand.

Transmission connected generators - The tariff comprises two separate elements:

- Locational – to reflect the costs of transporting power to and from different locations
- Residual – uniform charges to make up the transmission asset owners' remaining revenue requirements.

Demand customers (both transmission and distribution connected) - The charges are calculated based on the location of the demand customer and depend on whether the user is HH or NHH settled:

- HH customer charges are based on their average meter readings in the Triad periods
- Non-HH customer charges are based on the deemed usage during peak periods (16:00 hrs to 19:00 hrs) using the relevant settlement profile.[21]

Balancing Service Use of System (BSUoS) charges

These charges recover the cost of balancing the transmission system and the system operator function from users of the transmission system. The BSUoS charges are calculated daily as a flat tariff across all users and are payable by transmission connected generators and all demand customers. The charge is a unit based charge in £/MWh and varies by half hour. BSUoS charges are dependent on the balancing actions that National Grid take each day, however National Grid provide historical charges and a monthly forecast of BSUoS.

Losses

Network losses represent the difference between units of electricity entering and leaving the system. Transmission losses are about 1.7 per cent and are applied evenly across Great Britain and are charged 45 per cent to transmission connected generation and 55 per cent to demand. Distribution losses vary

[21] A load profile gives the Half Hourly (Settlement Period) pattern or 'shape' of usage across a day (Settlement Day), and the pattern across the Settlement year, for the average customer of each of the eight profile classes.

by region and voltage level and loss adjustment factors are applied accordingly; they range from 5 to 8 per cent.

Distribution Network Use of System (DNUoS) charges

The DNUoS charge covers the cost of operating and maintaining a safe and reliable electricity infrastructure between the transmission system and demand and generation customers. The Distribution Network Operators (DNOs) are set an Allowed Revenue to cover a price control period to cover maintaining, repairing, replacing and reinforcing network assets. However, the Allowed Revenue does not include costs directly paid for by customers, such as those for new connections.

Charges are paid by distribution network connected generators and demand customers through their suppliers and vary between the network levels at which they are connected:

	Common Distribution Charging Methodology (CDCM) applies to LV and HV connected (up to 11kV)	**EHV Distribution Charging Methodology (EDCM) applies to EHV connected (33kV and above)**
Distribution connected generators	• A fixed charge in p/MPAN/day, which varies between DNOs • A reactive power charge in p/kVArh	• A fixed charge in p/day • An export capacity charge p/kVA/day, which takes into account both local and remote elements of the asset cost • An exceeded export capacity charge p/kVA/day at the same rate as the export capacity charge.

Demand customers	• NHH metered
	    ○ A unit rate in p/kWh
	    ○ A fixed charge in p/MPAN/day
	• HH metered
	    ○ A unit rate in p/kWh with three rates depending on time of day: green; amber; and red
	    ○ A fixed charge in p/MPAN/day
	    ○ A capacity charge in p/kVA/day, which varies by voltage level and specifies a Maximum Import Capacity (MIC) which, if exceeded, incurs an extra charge
	    ○ A reactive power charge in p/kVArh
		• A fixed charge in p/day
		• An import capacity charge p/kVA/day, which varies by voltage level and specifies a MIC
		• An exceeded import capacity charge p/kVA/day – applied only if the MIC has been exceeded
		• A super-red unit rate p/kWh – applied during the seasonal ‘super-red time band’, which is defined by each DNO to correspond to peak time.

Embedded benefits

Embedded generation, which is generation or export from storage connected to the distribution network, receives a credit (the so-called embedded benefit) for relieving pressure on the network by generating close to demand customers. The value of these credits varies but can be a significant part of distributed generator income.

The different elements include:

- Triad benefit – generation is offset against the supplier's Triad demand within a GSP group and reduces the supplier's TNUoS bill. Where a supplier does not have an offsetting demand, the export is treated as negative demand and a credit is applied.
- BSUoS – as with the Triad benefit, generation is offset against demand to reduce the supplier's BSUoS charge in each half hour period.
- Generator Distribution Use of System (GDUoS) – generation is paid for every unit of electricity exported depending on the level at which it is connected:
    - LV and HV - a single unit rate in p/kWh is applied to intermittent generation. For non-intermittent generation, the credit is split into three time bands labelled red, amber and green with the credit rate highest for the red band.
    - EHV – only non-intermittent generation is eligible for a credit, which is payable for export during a super-red time band only (a subset of the red time band between November and February). Prices are locational and derived for individual sites.
- Losses – supplier's volumes at GSP are adjusted by loss factors before entering settlement. Generation is offset against demand, which reduces the total volume that losses are applied to, hence reducing both transmission and distribution loss charges.

A review by Regen of its members indicated that embedded benefits value to decentralised generators varies greatly depending on the type of generating technology, their location and the terms of their Power Purchase Agreement. Benefits also vary year-on-year for variable generators depending on whether they are fortunate to hit high load factors during the Triad and peak demand periods.

For a typical 1 MW wind farm asset operating in Cornwall at an average 30% capacity factor, <u>that hits the Triads</u> and has a 90% benefit pass through PPA, the combined embedded benefits of TNUoS and BSUoS payments have been calculated at circa £17-18k per annum or £6-7 per MWh. Given the wholesale price of power in recent months has been between £35 and £45 per MWh this income is potentially a significant part of a distributed generator's income. But it must be emphasised again that the level of benefits will vary greatly between projects and years.