Energy networks and distributed energy resources in Great Britain

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EPG Working Paper: 1406

Abstract:

This paper examines the rules and incentives governing electricity, gas and heat networks in Great Britain from the perspective of how far these facilitate or prevent a shift towards an energy system with more 'distributed energy resources', including flexible demand, local electricity generation and heat production, and energy storage. Much of the analysis focuses on electricity distribution network, where the greatest need for innovation is expected to lie. Most of the relevant rules and incentives arise from the economic regulation of networks, and from licence conditions and industry codes and standards. The paper goes on to describe the governance of these frameworks, and how that governance has evolved since privatisation. Finally, the paper offers an interpretation of why that evolution has taken the course it has.

Keywords: networks, smart grids, innovation, regulation, governance, demand-side response

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Date: October 2014

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Contents

List of acronyms

AMR	automated meter reading
BM	Balancing Mechanism
BSC	Balancing and Settlement Code
BSUoS	Balancing System use of Services (charges)
Capex	capital expenditure
CfD	Contract for Difference
CHP	combined heat and power
CUSC	Charging and Use of Services Code
D-Code	Distribution Code
DCUSA	Distribution Charging and Use of Services Agreement
DER	distributed energy resources
DG	distributed generation
DNO	Distribution Network Operator
DPCR	Distribution Price Control Review
DSR	demand Side Response
DUoS	Distribution Use of Service (charges)
ECC	Energy and Climate Change (Select Committee)
EHV	extra high voltage
ENA	Energy Networks Association
ER	Engineering Recommendations
ESCO	energy service company
EV	electric vehicle
GB	Great Britain
GDUoS	Generator Distribution Use of Service (charges)
GW	gigawatt
GWh	gigawatt hour
HP	heat pump
HV	high voltage
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
LCT	low carbon technology
LV	low voltage
MW	megawatt
MWh	megawatt hour
NG	National Grid
NTS	National Transmission System (gas)
Opex	operational expenditure
PV	photo-voltaic
RAV	regulated asset value
RoR	rate of return
RPI	retail price index
RIIO	Regulation + Incentives + Innovation + Outputs
SO	system operator
SQSS	Security and Quality of Supply Standards
STOR	Short-term Operating Reserve
TNUoS	Transmission Network Use of Service (charges)
Totex	total expenditure
TPCR	Transmission Price Control Review
TW	terrawatt
TWh	terrawatt hour
UNC	Unified Network Code

Energy networks and distributed energy resources in Great Britain[1]

1. Introduction: why does the demand side matter?

This paper examines the rules and incentives governing electricity, gas and heat networks in Great Britain (GB)[2] from the perspective of how far these facilitate or prevent a shift towards an energy system with more ‘distributed energy resources’, including flexible demand, local electricity generation and heat production, and energy storage. It also describes how the governance of networks, which shapes those rules and incentives, has evolved since privatisation, and offers an interpretation of why that evolution has taken the course it has.
The context for the paper is the desirability of a fundamental shift in the underlying design of the energy system from the supply side to the demand side. In the words of Strbac (2010: Ev14), “The whole culture and philosophy of the system is based on a predict-and-provide mentality”. Arrangements for gas and electricity, from production or generation, through to networks and retailing, have been designed to provide secure supply for whatever consumers demand. This system has been remarkably successful in its own terms, but is becoming increasingly outdated and problematic, for a number of reasons.

As energy service demand has grown, an infrastructure geared simply to meeting, as opposed to influencing, that demand has also grown. The resulting energy system we have is now very large and costly. As we move to decarbonise energy production, it is becoming clearer that this will be far easier and less costly the smaller is energy demand. Across a range of scenarios for GB energy system decarbonisation, those with lower demand are also those with lower costs (Steward 2014).

This is true not only of overall energy demand, but also of *peak* demand, which tend to occur at particular times of day and year (i.e. in the winter, in early evening). The energy system is effectively sized to meet this demand, so being able to make demand more flexible, to reduce peaks, will become increasingly important as decarbonisation proceeds (e.g. ECC 2010: 14-16, Strbac 2008). Reducing future peak electricity demand will be particularly important if, as

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[1] I would like to all those listed in Annex 1 for agreeing to be interviewed. I am also indebted to Catherine Mitchell, Caroline Kuzemko, Richard Hoggett and Tom Steward for long discussions on the issues covered in this paper and to Richard Lowes for giving advice on gas networks. Finally, I would like to thank Ed Reed and Judith Ward for extensive comments on earlier drafts. None of the above are responsible for any errors or misinterpretations.

[2] Energy networks in England, Scotland and Wales (i.e. Great Britain) are regulated by Ofgem under a common framework. Northern Ireland has its own energy regulator.

expected, increasing amounts of heat and transport energy needs are electrified. Ofgem (2010a) quantifies the potential benefits of reducing peak electricity load by 10% at between £550 million and £1.2 billion a year, although with more renewables and higher use of electric vehicles and heat pumps, the benefits are likely to be higher. Over ten years this would be between £5.5 billion and £12 billion, and should be seen within the context of Ofgem's estimate that roughly £200 billion will be needed in energy infrastructure to achieve low carbon targets (e.g. Ofgem 2010b). Beyond cost, achieving energy saving through much better energy efficiency and more flexible energy use will also have other benefits, including greater comfort in the home for poorer households and less resource use in supply chains.[3]

Energy efficiency and demand side flexibility are increasingly included with energy storage and generation/production of energy by consumers in a wider concept of 'distributed energy resources' (e.g. Agrell et al 2013, Ruester et al 2014, Glachant and Ruester 2014).[4] In particular, as distributed electricity generation and storage technologies become cheaper, it is expected that the model of centralised, large-scale electricity generation in GB will be replaced by a more distributed system. Such a system may also produce lower distribution losses, although it may not. It is uncertain exactly how far this process will, or should go; this will be related to how far such a transformation reduces or increases system costs, and may depend heavily on how variables such as the cost of electrical storage evolve. However, it is already underway in the UK with the growth of smaller scale wind farms and the rise of solar PV in the last few years.

Because policy debates are increasingly framed in these terms, this paper uses this wider DER concept as a likely key element of a future sustainable energy system. However, at certain points I also distinguish between demand-side response (DSR), distributed generation (DG), storage and energy efficiency. Of these, DSR and DG are currently the more important from the perspective of networks. This is for three reasons. One is that electricity storage is still expensive and not widely used. The second is that, as noted above, peak demand rather than overall demand is the key factor in determining network costs. Reducing demand at peak periods can be achieved by either greater efficiency (net of direct rebound effects) or DSR. However, much of the debate about the role of networks focuses on the latter because network

[3] Rebound effects from lower demand through higher efficiency are inevitable, but vary according to context and scale. The evidence suggests that rebound effects are highest at an economy wide level; direct rebound effects, especially in the domestic sector, are likely to be limited (Sorrell 2007). However, the rebound effect does not negate the importance and potential of achieving energy savings through greater efficiency.
[4] DECC has recently adopted a closely related 'D3' terminology, meaning demand reduction, demand side response and distributed energy (DECC 2014a).

charging can give stronger signals for DSR than it can for overall energy use. The third reason is that, under the current ‘supplier hub’ principle, networks in GB have no direct relationship with consumers and virtually no opportunities to engage them on energy efficiency.

Within this context, the focus of the paper is on energy networks, and has three aims. First, it lays out, at length, the relevant rules and incentives in the GB regulatory system that work for or against gas, electricity and heat networks becoming more demand and less supply oriented, in place in mid-2014. As part of this description, it provides some account of how rules and incentives have evolved since privatisation in the late 1980s.

The second aim is to give an account of the governance systems that have produced those rules and incentives, and how these have changed over time. Finally, the third aim is to offer some interpretations of *why* governance systems have evolved in the way that they have, producing the changes in rules and incentives observed in the first part of the paper.
This paper forms part of the EPSRC-funded IGov project on Innovation, Governance and Affordability for a Sustainable Secure Economy. It is based on a wide review of regulatory and commercial documentation, analyses by academics and think-tanks, and on interviews with a number of stakeholders in energy networks (see Annex 1).

The next section briefly explains why networks matter for distributed energy resources, in particular demand side flexibility, distributed generation and storage. Section 3 then examines the rules and incentives governing electricity distribution networks. Section 4 looks at electricity transmission, section 5 at gas networks and section 6 at heat networks. In section 7, the wider governance arrangements that produce network rules and incentives are discussed, including how these have changed over time. This section also offers an analysis of why network governance has evolved in the way that it has. Finally, section 8 briefly concludes.

2. Why do networks matter for the demand-side approach and what innovations in networks are needed?

In physical terms, networks lie at the centre of the energy system connecting the generation of electricity and the shipping of gas with supply to end users. Network design and operation will reflect the nature of the energy system in which they are embedded, and the current GB system has been set up to accommodate a system based on load following, i.e. able to carry sufficient gas or electricity to meet demand at any point, and large-scale centralised generation/production.

This arrangement has some immediate implications for network design. One is that distribution networks in any geographical area have to have sufficient capacity to carry energy that meets peak demand (across both time or day and season), with sufficient headroom to allow for a certain degree of equipment failure, which is currently defined in a deterministic way through engineering rules. Another is that high-voltage and high pressure transmission networks play a central role, transporting bulk power and gas from a limited number of points of power generation and gas production to grid supply points on the distribution networks. The need for a significant capacity margin means transmission networks also have to have a degree of redundancy built in.

In recent years, both total demand and peak demand for electricity and gas in the UK have actually declined somewhat, partly because of the extended economic depression and possibly also due to efficiency programmes. Between 2005 and 2012, total electricity consumption fell by 9% from 357TWh to 325TWh, and winter peak demand has fallen by a similar amount.[5] Gas consumption, which was consistently over 1,000TWh a year in the second half of the 2000s, was around 840TWh in 2012.[6]

On the other hand, especially for electricity distribution networks, many assets (wires, transformers, switching equipment etc.) are over 40 years old. Some of these date back to a major wave of investment during the nationalised period in the 1960s (e.g. Pollitt and Bialek 2008 Figure 1; Bolton and Foxon 2010: 15) and even by the late 2000s an estimated 70% were reaching the end of their design lives (Mitchell 2010: 150). Gas networks are also quite old, with a major safety issue being the replacement of iron piping by modern plastic pipes (HSE 2010).

[5] https://www.gov.uk/government/statistical-data-sets/historical-electricity-data-1920-to-2011

[6] https://www.gov.uk/government/statistical-data-sets/historical-gas-data-gas-production-and-consumption-and-fuel-input-1882-to-2011

Thus, if the energy system remains fundamentally unchanged, long-term investment needs for renewing the existing ageing network will be large. At the same time, technology for networks, and in particular information and communication technologies, has evolved since the 1960s. There is a huge potential to increase the ability of electricity distribution companies to remotely and automatically monitor and control the state of their networks, in ways that would in many cases reduce conventional capital costs by deferring or avoiding reinforcement. In other words, there is an opportunity to *modernise* networks.

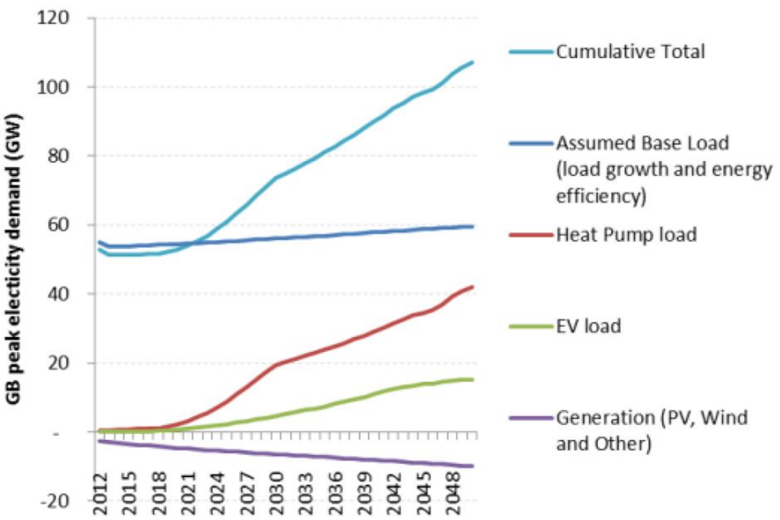
At the same time, there is the argument that networks need to be changed for a future energy system. There are a number of inter-related potential challenges that arise:

- accommodating new sources of variable low carbon electricity generation. Because renewable generation from wind and solar varies over time, networks sized for their peak generation will be utilised for a lower proportion of the time than is the case for conventional thermal plant. New approaches to engineering standards, network design and network access may be required
- wind resources are often located in remote locations that the current network does not reach, or in which it is weak.
- there is likely to be significantly greater low-carbon electricity generation connected to distribution networks, either micro-generation in the form of solar PV or larger sources such as on-shore wind farms or biomass combined heat and power (CHP) plants. Distribution networks[7] were not originally designed to accommodate generation, especially on low voltage parts of the network. Significant amounts of generation will raise a number of challenges, such as increased fault level due to fault current from synchronous generation; protection against faults, fault ride through, facilitation of islanding and voltage control (Baker and Chaudry 2010: 8-9).
- electrification is expected to play a major part in the decarbonisation of transport and heat (DECC 2013b: 102-105). This will require distribution networks to accommodate a huge increase in peak demand from electric vehicle charging and heat pumps, which they currently do not have the capacity to do. Wilson et al (2013) note that the energy in daily gas demand in winter can be 4 times that of electrical demand and is considerably more volatile. Heat demand should decline over time as homes get more insulated, but there will still be a lot of increase in electricity use. They estimate that shifting even 30% of heat demand to electricity would mean daily electricity demand doubling if resistive heating is used, and increasing by 25% if heat pumps are used. Peak demand increases would be larger, and

[7] Defined as 132kV and below in England and Wales, but now 33kV and below in Scotland – see below

‘without substantial investment in transmission and distribution infrastructure, the UK electricity system is unlikely to be able to accommodate even a fraction of the additional power requirements associated with the transfer of heat demands at current levels’ (ibid: 303-304). The move to electric vehicles and consequent demand for charging will add to this challenge (Pieltaijn et al 2011, Kampman et al 2011). Overall, Pudjianto et al (2013: 77) estimate that the electrification of heat and transport could increase daily electricity use by 50%, while doubling peak demand. In a scenario of low-carbon technology uptake consistent with the Committee on Climate Change’s Fourth Carbon Budget, developed by the Smart Grid Forum, peak electricity demand could increase from just under 60GW now to over 10GW by 2050 (Figure 1)

Figure 1: Projected increase in peak electricity demand with growth of low carbon technologies under the Smart Grid Forum Workstream 3 Scenario 1.15



Source: Element Energy 2013

It is increasingly argued that these challenges for electricity distribution networks will have to be met with the help of distributed energy resources. Distributed generation and the energy storage potential of electric heat stores and electric vehicle batteries could potentially provide a number of services (e.g. Poudineh and Jamasb 2014, Agrell et al 2013, Ruester et al 2014, Glachant and Ruester 2014). These include supporting system balancing at a national level (e.g. Beaudin et al 2010), but also balancing demand and supply more locally than is the case at present thus replacing centralised generation, and smoothing out peaks in demand and managing voltage and reactive power problems, thus deferring or avoiding investment in what would otherwise be even larger networks (e.g. Strbac et al 2010, Pudjianto et al (2013: 77), ECC 2013a: 13-14).

However, making these concepts a reality will entail both new commercial models and new infrastructure, adding up to a different vision for electricity distribution networks from their current form (Eyre and Willis 2006, DECC 2009, Cary 2010, IET 2011, ENSG 2009, Smart Grid Forum 2014).

There is no single agreed definition of a smart grid. The SmartGrids European Technology Platform (2011) define smart grids in terms of the ultimate outcomes it is intended to facilitate: ‘‘electricity networks that can intelligently integrate the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies’’. DECC’s (2009: 1) definition of a ‘smarter’ grid focuses on functions and more intermediate outcomes:

> *Building a ‘smarter’ grid is an incremental process of applying information and communications technologies (ICTs) to the electricity system, enabling more dynamic ‘real-time’ flows of information on the network and more interaction between suppliers and consumers. These technologies can help deliver electricity more efficiently and reliably from a more complex network of generation sources than the system does today. With a progressively smarter grid, operators get more detailed information about supply and demand, improving their ability to manage the system and shift demand to off-peak times. Consumers are offered far more information about, and control over, their electricity use, helping reduce overall demand and providing a tool for consumers-- to reduce cost and carbon emissions.*

At a high level of generalisation, smart grid technologies should make networks more observable in real-time and controllable, including via automation.[8] These functions make active network management (McDonald 2008) on distribution networks possible, where local system operators can monitor power flows, anticipate faults and manage demand peaks through drawing on distributed energy resources. The system operator and other actors must be able to communicate with distributed generators, storage devices, heat pumps, electric vehicles and appliances through smart meters, sending appropriate price signals or allowing automated control. A more detailed, technical account of smart grid functionalities has been developed by the Smart Grid Forum Workstream 3 (SGF 2011).

[8] In practice, many aspects of smart grid functionality, including remote automated control of equipment, has already been in place for many years on the higher voltage parts of GB electricity networks (SGF 2014a). The ‘dumb’ section of distribution grids is the low voltage, street level part of networks. For this reason, some prefer the use of the term ‘smart*er* grids’.

Thus at the electricity distribution level, the development of a system more focused on the demand side involves at its heart major innovations in technologies, operations and business models. A greater role for distributed energy resources and balancing at local level in the electricity system also has implications for high-voltage transmission networks (ECC 2013a: 14, IET 2013). These are currently designed to facilitate centralised generation and bulk power transport over long distances. On the one hand, greater local balancing implies a smaller, more residual role for transmission networks. On the other hand, some new renewable resources (including wind, tidal and wave) are best in areas remote from centres of demand, and greater integration in the use of transmission-connected renewables and DER across Europe implies the need for new transmission capacity in some places and for greater interconnection. Overall, the most important issue is integrating objectives for the electricity system as a whole across distribution and transmission. Currently, this is done on the basis of giving priority role to ensuring centralised large-scale generation, whereas in future it should be done on the basis of a priority role for DER.

In gas, the key issue is the long-term future of the network, given that most heat demand in future will be met through electricity. Unless alternative uses for it are found for it, the use of the gas network could radically decline, unless (Dodd and McDowell 2013). In the interim, there are also question about whether network rules and incentives support reduction and greater flexibility of gas use.

Finally, while much heat demand will be electrified, some heat will in future may be met through district heating (partly provided by CHP) fuelled sustainably from biomass or some other sources (DECC 2013b). Heat networks are currently largely unregulated in the UK, in contrast with countries in which such networks have played a significant role (especially Denmark).

3. Current rules and incentives for electricity distribution networks

As discussed in section 2 above, in order to build an electricity system in which flexible demand and distributed generation play major roles, electricity distribution systems will need to undergo a particularly major transformation. Distribution networks are operated at a range of voltages, with some larger customers and some generation (e.g. some wind farms) connected directly to the extra-high voltage part of the network (22kV and above). In addition, there are a larger number of 100kW+ customers with half-hourly automatic meter reading (AMR) enabled metering, some of whom are connected to high voltage parts of the network, and smaller businesses (profile classes 5-8) should also all have AMR metering.

Taken together, all half-hourly customers make up less than 1% of meters, but account for over half of the volume of electricity flowing around networks (e.g. Element Energy 2013: 47).

These parts of the distribution network are closer in nature to the transmission network (indeed in Scotland 132kV lines are part of the transmission network) and issues arising from connected generation, such as voltage fluctuation, can already be managed. Customers on these parts of the network can already technically offer demand side response, for example in ancillary services to the national system operator, if they are of sufficient size.

The bigger challenge, and where more innovation is needed, is in the low voltage (LV) part of the networks. LV networks serving households and small businesses make up the vast physical bulk of the network and the majority of customers, even though they carry only around half of the power on distribution networks. These customers still have ‘dumb’ meters, and DNOs also have virtually no automated visibility of the state of LV networks. While smart meters with the capacity to communicate the characteristics of power being served to households and small businesses should be universally available by 2020, considerable innovation and investment will be needed to make networks themselves smarter. This section considers the main factors influencing how far this is being facilitated or slowed.

Electricity distribution networks have been governed as separate elements within energy value chains since the unbundling of supply from distribution in 1997. Investment in these networks has been governed by a series of successive five-yearly price control economic regulation regimes, which determine how much distribution network operator (DNO) companies are allowed to raise in revenue to cover operational and capital expenditure in the price control period. Agreed costs are recovered through distribution network charging, for both network use and for connection charges. Charges apply to both consumers and generators of electricity, with the design of these charges being determined through a code that is managed by distribution network companies and overseen by Ofgem. Signing up to and following this and other technical distribution codes is a condition of the licence that DNOs require to operate.[9]

While this overall structure of governance arrangements has not changed since 1997, specific elements within it, especially in the details of economic regulation, have evolved over the years. Accounts of this history can be found in Jamasb and Pollitt (2007), Pollitt and Bialek (2008), Woodman and Baker (2008), Ofgem (2009a), Shaw et al (2010) and Cary (2010), as well as in successive price control documents. In this section, my main focus is on the *current* governance arrangements. For economic regulation, this means a particular examination in the change from the current price control (DPCR5, 2010-2015) which was conducted under one set of rules (RPI-X) to the forthcoming one (RIIO-ED1, 2015-2023), which is being conducted under new rules (RIIO).

3.1 Economic regulation

Since privatisation from the late 1980s onwards, energy networks in GB have been regulated as natural monopolies through a price-cap regulation regime (sometimes called incentive regulation – see Joskow 2008). The account given here provides details based on the regulation of electricity distribution networks, but the general principles apply also to electricity transmission and gas networks, which are regulated under the same overall frameworks.

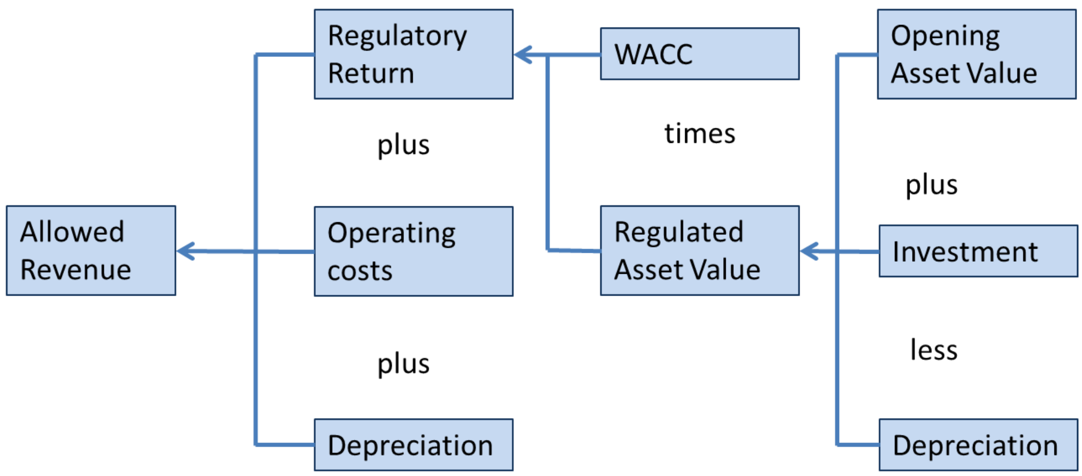
Electricity distribution network operators (DNOs) have been regulated as separate companies since the introduction of retail competition, effectively since 2000. Until 2015, electricity distribution will be regulated under a regime known as RPI-X; after that date a new regime, known as RIIO (Revenue = Investment + Innovation + Outputs), will come into operation. This section first examines the RPI-X regime and the incentives it created, especially in relation to innovation. It then goes on to assess specific incentives for R&D on electricity distribution networks that were introduced from 2005 onwards. Finally, it looks at changes in the wider regulatory regime, many of which are being introduced under RIIO.

[9] Suppliers are also required to follow the technical (Distribution Code) and commercial (DCUSA) distribution codes.

3.1.1 RPI-X

Distribution price control review (DPCR) periods have been historically been roughly 5 years. In advance of each price control period, network companies and the regulator agree a programme of capital expenditure and operational expenditure on networks over the period. In the last two periods (DPCR4, 2005-2010 and DPCR5, 2010-2015) a set of performance targets and incentives (financial rewards and penalties) have also been put in place. At the same time, to ensure that the whole programme can be delivered, the regulator allows each network company to earn a certain amount of revenue to cover the costs of capital. The capital investment in each price control period is not paid for directly by revenue from charges to customers, but rather companies are allowed to raise capital, with allowed revenue covering repayment of that capital over time. As shown in Figure 2, this revenue allowance is built up in a series of stages. First, the regulatory asset value (RAV) of the company for the price control period is determined. This is calculated as the opening RAV from the previous period, plus planned investment over the price control period, less depreciation. The assessment of the opening RAV is on the basis of the previous opening RAV plus actual investments made over the previous price control period that the regulator considered 'efficient' (i.e. justified on the basis of the previous price control).

Figure 2: Price cap regulation 'building blocks' approach



Source: Ofgem 2009a

The regulator then makes a judgement on what the cost of capital (weighted between debt and equity) will be for a well-run efficient company, known as the weighted average cost of capital (WACC). The WACC is effectively the allowed regulatory rate of return, and multiplied by the RAV gives the allowed regulatory return. This return is what the regulator considers a well-run efficient company will need to cover investment costs. Provision is also made for operating costs (benchmarked at the most efficient level by comparing across network companies) and depreciation.

Allowed revenue is then spread across the price control period to give annual allowed revenue, adjusted for inflation (i.e. the retail price index, or RPI) and then adjusted further by an X factor which represents assumed improvements in efficiency or productivity over the period. Up until the mid-2000s, the X factor bore down on network costs, and allowed revenues (and network charges) fell considerably, mainly through savings in operational expenditure. However, with assets ageing by the mid-2000s, increases in allowed capital expenditure meant that the regulator started to choose a positive X (Ofgem 2009a).

Network companies then recover their allowed annual revenues through charging generators and suppliers, who in turn pass costs on to final consumers. Any discrepancies between allowed and actual revenue are covered by adjusting charges in the following year.

Having set the revenue that network companies are allowed to earn, the RPI-X framework then involves a set of explicit incentives. First, companies can keep a share of any savings they can make against projected costs (or alternatively incur part of any overspend as a penalty). Under RPI-X, there were different incentives for opex and capex (Crouch 2006: 241). Opex allowances are based on benchmarking amongst companies, and if companies could beat their allotted opex figure then they could keep a share of the difference (e.g. Ofgem 2009a: 26). It is widely argued that this regime incentivised network companies to cut opex and shed considerable amounts of labour in the first ten years. For capex, what is judged to be efficient investment is added to the company's RAV at the end of the price control period at the *actual* cost. However, for the duration of the price control period, companies can earn the *allowed* rate of return and depreciation on every pound of savings between actual and allowed cost (Burns and Reichmann 2004), thus providing an incentive to be efficient in capital spend.

Up until DPCR5 (2010-15), incentive rates were different for operating and capital expenditure, which gave an incentive for companies to skew actual spend towards capex. In DPCR5, total expenditure (totex) is now subject to a single incentive scheme which rewards savings and penalises overspend relative to allowed expenditure. In theory, this should give DNOs greater flexibility in substituting opex for capex and remove their perverse incentive to maximise capex (Ward et al 2012a: 54).

Figure 3: Estimated effects of regulatory incentives on DNO rate of return on equity, DPCR5

Source: Ofgem 2009d

The overall cost efficiency incentive has probably had the largest effect on actual, as opposed to allowed rates of return for DNOs. Figure 3 shows Ofgem's expectations of effects on rates of return on equity for the current DPCR5, (2010-2015). The central blue band represents the potential for higher or lower rates of return arising from efficiency incentives, and produces the largest single effect.

Network companies can in practice earn an actual rate of return significantly higher than the baseline allowed rate. For example, while the baseline allowed rate of return for National Grid Electricity Transmission under RIIO-T1 is just over 7% (Ofgem 2012a), the company achieved an 11.8% on equity in the year to March 2013 (National Grid 2013), and it has also outperformed in 2013-14.[10] Almost all the electricity and gas distribution companies have historically outperformed on their allowed rate of return, with most achieving 8-11% (Ofgem 2009c), and networks remain one of the most profitable parts of the value chain.[11]

3.1.2 Implications for innovation

As described in section 2 above, the move to a low-carbon energy system is likely to involve significant expansion of demand on low-voltage electricity networks and more distributed generation, some of which will be variable. Such changes could be accommodated through existing technical and commercial arrangements, but the resulting investment requirements would be very large indeed, as would losses. The combination of the use of ICT on networks to give greater visibility and control, along with new technologies such as storage and new contractual arrangements for demand response and distributed generation offer the prospect of significantly reducing costs and losses against a BAU model. Such changes imply a substantial amount of technological and organisational innovation, and a regulatory system that incentivises that innovation. This theme has been widely recognised in both academic and policy literatures (e.g. Mitchell 2010, Woodman and Baker 2008, Pollitt and Bialek 2008, Cossent et al 2009, ENA 2009b, Bolton and Foxon 2010, Shaw et al 2010, Cary 2010, Smart Grid GB 2010, Skillings 2010, IET 2009, Sansom 2010, Ruester et al 2014).

In contrast, network companies have historically been seen as largely uninnovative and risk averse (Ofgem 2009b: 21, Sansom 2010). In 2010, a senior Ofgem figure argued that a combination of engineering culture and economic incentives produced a "bias amongst the

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[10] http://www.cornwallenergy.com/cms/data/files/pdf/htmlemail/140616_es_429.pdf

[11] For example, networks alone provided half of SSE operating profits in 2014 – see http://sse.com/media/233432/SSE-Full-Year-14-results-presentation.pdf

network companies to solve problems with investment in physical assets" (Smith 2010: 5)[12] and that "it would be crude but not an unrealistic simplification to say that the way energy networks are designed, built and operated has not changed significantly since they were built in the post war period" (*ibid*: 9). They have been staffed by engineers who have a "natural desire…to put more faith in physical assets than commercial arrangements and new contracting and pricing arrangements to manage capacity constraints or uncertainty".

Much of the use of network infrastructure is determined at the competitive ends (i.e. generation and supply) of the value chain in which they sit, and these activities are themselves subject to policy and political risks, as well as being largely beyond the control of network companies. In response, DNOs have been risk-averse, acting when required to by users (for example seeking to connect) or by the regulator, but not proactively (e.g. Shaw et al 2010: 5934). They have tended to focus on maximising allowed revenue and beating the allowed rate of return. As a result, networks have traditionally been (and been seen as) low-risk businesses, attracting capital (especially debt) at a discount.

Since privatisation, arguably the major innovation that companies have made has been in short-term cost reduction, mainly through labour shedding. Within a 5 year price control period, companies really focused on achieving savings in the first 2-3 years, before negotiations started on the next price control. Network firms have historically lacked the capacity, skills and incentives for major long-term technological and operating innovation. Investment by DNOs in longer term innovation was low; by 2004, UK network companies were spending less than 0.1% of revenue on RD&D (Pollitt and Bialek 2008).

However, as the regulator itself recognised (e.g. Ofgem 2009e), the problem lay ultimately in the regulatory regime rather than with the network companies. A step change in innovation by the latter would only occur with a regime that incentivised innovation, and it was widely argued that the RPI-X regime did not do that, for a number of reasons.

Standard economic analysis recognises various reasons why companies may be deterred from risky innovation in a competitive market, such as knowledge spillovers and asymmetric information in capital markets, which is the basis for policies such as R&D tax credits. In the context of regulated monopolies, however, a number of additional specific barriers may be at work. The most basic problem was that there was no major driver for companies to develop new

[12] Sometimes characterised as a 'fit-and forget' approach (e.g. Shaw et al 2010: 5930)

technologies as long as the costs of existing technologies were funded within the regulatory framework (Ofgem 2009e: 6). In addition, as noted in section 2 above, many of the benefits of innovation on networks would accrue to a range of parties beyond network companies themselves, including consumers, suppliers, and owners of distributed generation (Ofgem 2009e: 6, ENA 2009b, IET 2009, Bolton and Foxon 2010, Smart Grid GB 2010, Sansom 2010, Ruester et al 2014: 3).

If network companies were given a basic incentive to innovate, other aspects of the RPI-X regulatory framework were also potentially problematic. One of the most basic issues was that up until 2010, the revenue that DNOs received in price controls varied directly with customer numbers and electricity distributed (i.e. in kWh) (Ofgem 2009d: 42). This is a clear disincentive for DNOs to undertake any innovation (or indeed any measure) that would cut demand (Shaw et al 2010: 5930). In DPCR5, this revenue driver was removed, and replaced by a link to the number of 'high volume low cost' (i.e. essentially low voltage household and SME) connections and a reopener to limit the exposure of DNOs to smaller or larger than expected demands on their networks. This gives companies an incentive to expand the number of consumers connected to their networks, but not the amount of electricity supplied to those consumers.

A second reason why companies might not innovate was that any expected benefits of innovation may not accrue for some time (Ofgem 2009e: 6). Not only may such benefits be heavily discounted, but if they occurred mainly in future price control periods, companies faced the risk that their investments in innovation would not be judged to be efficient and so would be disallowed from inclusion in approved expenditure.

A third, somewhat complex issue was how the RPI-X regime influenced the balance of capital and operational expenditure. As noted above, the regime treated these two types of expenditure differently, with different explicit incentive schemes to encourage cost reduction. However, there are four broad arguments in the academic and policy literature that the framework also created unintended incentives that further distorted this balance:

1. Network companies will have an interest in *bidding up investment allowances* as much as possible. The higher the allowed capital expenditure, the more room companies have cost savings (Baker et al 2010). This creates an incentive for companies to seek to set the initial allowed spend as high as possible, and leads to gaming, "with companies bidding for very high opening capital and operating expenditures and then rapidly cutting them once the formula was set" (Helm 2004: 18). Typically, companies will make initial proposals for costs

that are significantly higher than those eventually agreed by Ofgem.[13] While the regulator is clearly cutting the initial proposals down significantly, it faces a fundamental problem of asymmetric information, since the companies know more about true costs than it does, despite assessments from engineering consultants, and companies are still likely to be receiving inflated investment allowances.

2. Incentive regulation such as RPI-X has the potential to lead to *underinvestment* in networks once the capex settlement has been agreed. (i.e. ‘sweating the assets’), because this increases the difference between allowed and actual capex and maximises gains within the regulatory period(Giannakis et al 2005, Égert 2009, Jamasb and Marantes 2011). This argument applies especially if company owners have a short term view on investment, because they will focus on reducing costs at the expense of service quality.

3. By contrast, applying more to owners with a long term perspective, network companies have an incentive to *increase actual capital investment*, because the greater is capital expenditure, the larger is the growth of their regulated asset values (RAV) (e.g. Baker and Chaudry 2010: 5-6, Strbac 2010). There are several reasons why this might be the case. The RAV represents the value of the company, and is the base to which an allowed rate of return is set, so that a larger RAV means higher absolute allowed returns. This is important for the type of investors typically interested in network utility businesses, i.e. ‘yield investors’ seeking index-linked steady growth. A larger RAV, representing the assets of the company, may also help to lower risk for investors and therefore the cost of capital.

The first of these effects, which applies to the allowed (i.e. *ex ante*) capital expenditure, is consistent with either of the other two effects, which apply to actual (i.e. *ex post*) capital expenditure. However, these latter two potential incentives are somewhat contradictory, having opposite effects on how actual DNO behaviour. Which of these effects dominates may depend in part on whether owners of network companies take a short-term or long-term view. In the early post-privatisation period some networks were owned by US parent companies seeking quick returns; many were then bought by the vertically integrated Big 6 companies, potentially seeking a hedge against network costs, but most have now been sold on to infrastructure funds, which tend to take a longer term view but also seek low levels of risk.

[13] For example, in the transmission price control running from 2007 to 2012, NGET’s initial capex proposal was £3.816 billion, whereas Ofgem’s final proposal was £2.997 billion, a difference of over 21% (Ofgem 2006). Gas distribution companies’ initial proposals for capex under RIIO-GD1 were 23.5% than the final settlement (Ofgem 2012b, Table 7.2).

4. A fourth and final effect is associated with the cost of capital. Ofgem has a statutory duty to ensure that the secure running of networks is financeable, so it must allow companies enough of a return to secure capital. It must therefore make a judgement of what it thinks the cost of capital for companies is. Again, however, it faces an asymmetric information problem, despite undertaking research with the capital markets. This arrangement not only gives companies an incentive to secure capital as cheaply as it can, but it also incentivises them to bargain as hard as they can with Ofgem over the WACC, ultimately using the risk on unfinanceability as a threat. When companies can secure capital at an actual cost that is lower than the allowed cost, this may also give them an incentive to seek to *substitute capital for labour* (i.e. the Averch-Johnson effect).

The overall impact of all these effects on innovation is unclear. Ruester et al (2014: 3) argue that use of DER in a smart grid approach can decrease opex compared with BAU but that the effects on capex are not obvious. Innovative approaches can reduce capex in the long term if grid investments can be deferred, but in the short term significant investments in ICT infrastructures may be needed. Overall smart grid cost-benefit analyses give positive figures for net avoided reinforcement and extension, but these are much clearer in the long-term than the short-term (ENSG 2010: 16-22, Strbac et al 2010, SGF 2012b).

However, the wider point is that the balance of opex and capex may well change as smart grid approaches are adopted and grow, and both the explicit and implicit incentives in the RPI-X framework potentially distorted this balance (Ruester et al 2014). There were calls to end the distinction in how efficiency incentives were applied by bringing the two types of expenditure together in a single total expenditure (totex) incentive (Pollitt and Bialek 2007, Cary 2010).

The account above can be summarised as follows:

- The shift to a demand-side focused energy system requires innovation in network investment and operation
- Electricity distribution network companies have historically been seen as risk averse, and lacking in the skills and capacity for innovation
- The RPI-X framework offered no incentive for innovation as long as the costs of solving network problems using existing technologies and operational approaches were funded from allowed revenue
- Companies have a basic driver to grow the size of the business, and would be opposed to permanent significant reductions in peak demand. However, even the partial electrification

of heat and transport is likely to lead to an increase in electricity demand and networks, even with smarter grids and the use of DER.

- Until recently, allowed revenue was linked directly to electricity consumed, again providing an incentive against innovating for demand reduction
- Benefits of innovation may not come until after the end of the price control period
- Companies have an interest in bidding up the allowed capital expenditure and allowed cost of capital
- A set of implicit incentives distort the balance between capital and operational expenditure, and therefore smart grid investments involving changes in both.

Over time, Ofgem began to change the regulatory regime to respond to some of these problems. An account of why and how this happened is given in section 7 below; here I describe what the most important changes have been, and their actual and potential effects on innovation for the demand side. First I look at specific incentives for R&D by DNOs, and then in section 3.1.4 I look at some of the changes in the wider regulatory framework. 3.1.5 goes on to assess how far these changes are likely to accelerate innovation over the next 10 years.

3.1.3 Incentives for innovation

In DPCR4, running from 2005 to 2010, two new mechanisms created dedicated funding pots for experiments in technological and commercial innovation with the aim of stimulating DNO activity. One was the Innovation Funding Incentive (IFI), covering 'all aspects of distribution system asset management' (Ofgem 2004: 48), which was capped at 0.5% of allowed revenue and available on a use-it-or-lose-it basis. Ofgem allowed 90% of the costs of IFI projects to be recovered in the first year of the price control, but this tapered off through the period to 70% in the fifth year, in order to incentivise early take up. The IFI was seen as relatively successful, although still small-scale. Spending by DNOs under the IFI increased from around £2 million in 2003/04 to around £12 million in 2008 (Jamasb and Pollitt 2011: 313) plateauing to 2011 (Ofgem 2012b: 53) and then declining as the successor LCNF scheme came in (see below).[14]

The second mechanism was Registered Power Zones - a scheme aimed at demonstrating innovative solutions for the connection of new distributed generation on sections of network

[14] IFI funding went to a wide range of projects including: real time transformer thermal rating LV network automation; superconducting fault current limiter testing; load forecast scenario modelling; substation environmental monitoring, voltage control and active network power management; overhead line incipient fault detection; novel conductors for 33kV and 132kV lines to increase capacity and reactive power compensation. Full reports can be found at: http://www.smarternetworks.org/Project.aspx?ProjectID=737#downloads

(Ofgem 2004). DNOs were allowed additional revenue for each kW of DG connected, capped at a total of £500,000 per DNO per year. However, only a handful of schemes have materialised (Woodman and Baker 2008: 4529; Bolton and Foxon 2010: 17). Based on this experience, there were calls to increase the scale of funding (Pollitt and Bialek 2008, Mitchell 2008, Cary 2010), and Ofgem itself acknowledged the need for more ambition (Ofgem 2009e: 6-7).

In DPCR5 (2010-2015), a new Low Carbon Network Fund (LCNF) was set up, which allowed DNOs to bid for up to £500 million over 5 years (Ofgem 2010), an order of magnitude larger than the IFI, and which funded demonstration projects rather than basic R&D. Ofgem also initially took a more hands-off approach with LCNF, using a competition approach that it hoped would transform DNO culture, although it has latterly started to track project costs more closely (Deasley et al 2014: 30-31).

The LCNF comprises two tiers, one allowing DNOs to recover most of the costs of smaller projects in allowed revenue, and another for larger projects in the form of a competitive fund of £64 million a year. The LCNF allowed DNOs to cooperate with ICT firms, suppliers, generators and consumers in projects, and also required findings from projects to be shared publicly. Essentially the same structure for RD&D funding will be continued into the next price control period (2015-2023), with a network innovation allowance similar to tier 1 LCNF and an innovation competition similar to tier 2 LCNF. As of April 2014, £22 million has been allotted under Tier 1, and just under £300 million under Tier 2.[15] This scheme allowed DNOs to cooperate with suppliers, generators and consumers in projects, and also required findings from projects to be shared publicly. The LCNF is the largest programme involving demonstration projects (as opposed to just upstream research) in Europe (SGF 2014a: 18),[16] and there is now an annual conference promoting the findings.

In 2015, a new price control will be brought in under the new RIIO regulatory approach (see below section 3.1.4). For electricity distribution, the LCNF will be replaced by an 'innovation stimulus' (Ofgem 2013b: 97). This consists of a Network Innovation Competition (NIC), in which companies bid for funds for large scale projects, similarly to the LCNF, and a use-it-or-lose-it Network Innovation Allowance (NIA) for smaller projects, of up to between 0.5 and 1 % of revenues. The NIC is resourced at around £90 million a year for the first two years of RIIO-ED1, i.e. to 2017, roughly the same in real terms as the LCNF.

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[15] http://www.smarternetworks.org/Index.aspx?Site=ed, accessed on 29 April 2014

[16] Although by funding per person and by electricity use, the largest investor in R&D by far is Denmark.

The NIC also allows any distribution licensees (e.g. suppliers, TOs, IDNOs, generators) to make proposals for projects. This addresses an issue in the LCNF rules related to fragmentation in the electricity value chain (see above section 2). As Deasley et al (2014: 33) point out, the benefits from demand side innovation projects potentially fall to others (such as suppliers and generators) as well as network companies, and this is supposed to be reflected in contributions of other actors involved in trials to project costs. However, whether or not a particular approach provides what value to which actors may well not be clear before the project takes place, and if others have no access to an equivalent to the LCNF, those contributions may not be forthcoming. At the same time, the LCNF requires that clear benefits to specifically networks are demonstrable for funding to be granted. Deasley et al (2014: 33) find evidence that a lack of DNO-specific benefit or lack of funding from other parties makes bids less likely to succeed.

3.1.4 Incentives for connecting distributed generation

Smaller scale electricity generation connected to distribution networks will play an important role in an electricity system more oriented to the demand side. A key element in the transition is moving the design and operation of distribution networks away from an approach based on the one-way flow of power from the grid supply point to homes and businesses and towards an approach that involves managing both consumption and generation.[17]

However, for distributed generation (DG) to play this role, its growth must be facilitated by DNOs. In part this depends on network planning at the macro-level, and incentives and the treatment of uncertainty in economic regulation (see below section 3.1.6). However, at the micro-level it also depends on how access and connection work and the degree to which they are a barrier to DG growth. The other factor is charging, which is discussed in section 3.2.2 below.

The history of attempts to make distribution networks more facilitating of DG stretches back at least to the late 1990s, with the formation of the Embedded Generation Working Group and later the Distributed Generation Working Group. These bodies lobbied for easier connection at lower cost, and DPCR4 (2005-2010) saw the introduction of a financial incentive for DNOs to

[17] It should be noted that DG can contribute to a reduced demand for centralised power provided via transmission and distribution networks in three ways: automatic (i.e. by reducing on-site generation), inadvertent (i.e. by unmetered ‘spill’ meeting other demand locally but with no supply contract and no visibility at present for DNOs) or intentional, where there is metered export (Andrews 2013). It is actually only the last type of generation that would pay distribution charges. The roll-out of smart meters should in principle eliminate the second type.

connect DG at the lowest reinforcement cost (Shaw et al 2010: 5929; see also Ruester et al 2104 and De Joode et al 2009).

However, these measures failed to lead to any significant growth in DG in the DPCR4 period. This may have been due to many factors (including planning, obtaining a reasonable PPA etc.), but it is also the case that the DG incentive in many cases may have been offset by disincentives to connect DG elsewhere in the regulatory system. Up to and including DPCR4 the allowed revenue of the DNO increased or decreased in line with energy distributed, which disincentivised DNOs to connect distributed generation where a significant proportion of energy was consumed on-site, as this would outweigh the DG incentive (Shaw et al 2007). Similarly, De Joode et al (2009) examine the financial effects of increased DG of different amounts and types using a model of an 'average' UK DNO and come to the conclusion that these can be positive at low levels of penetration and concentration, but become negative at higher levels.

By 2012, Ofgem argued that the DG incentive had had little effect (Ofgem 2012). More fundamentally, DNOs did not see connecting and managing DG as part of their core business, and tended to want to deal with projects on a piecemeal basis (Mitchell 2010: 153; Bolton and Foxon 2010: 16, Cary 2010: 68). Proposals for how to remedy this situation mainly focused on increasing the incentive to reduce losses, as more DG would help with loss reduction (Shaw et al 2007, Cary 2010, Pollitt and Bialek 2008),[18] and on the need to take a more strategic and coordinated approach to DG connection (e.g. Cary 2010: 68).

The RIIO framework drops the DG incentive, which Ofgem recognised was ineffective and too complex. Instead, Ofgem has decided that DG should be treated within the general framework of incentives for good connection and other services that covers demand users: "In RIIO ED1 there will be a range of incentives and mechanisms to encourage DNOs to better facilitate the connection of DG to the network" (Ofgem 2013b: 26). Three mechanisms are mentioned in particular: one to incentivise engagement with major customers, which includes distributed generators, one to penalise failure to meet minimum connection times and quality, and one broader measure of customer satisfaction. (*ibid*: 28-29). The financial penalties involved in the mechanisms are limited, although higher than for DPCR5 (*ibid*: 80-82). This approach builds on the introduction of a set of standards for DNO interactions with prospective and connected

[18] See section 3.1.5 below for a discussion of distribution losses incentives

distributed generators introduced in the licence condition in 2010.[19] These standards laid out timelines and conditions for providing customers with estimates, quotations and schedules for completion of works. By contrast with this general approach, Pollitt and Anaya (2014) argue for a specific 'smart connection' charge for offering non-firm connections to variable DG (essentially wind) that would defer network reinforcement requirements, to replace the removed losses incentive (see below section 3.1.5).

More recently, Ofgem has set up a Distributed Generation Forum, to facilitate greater dialogue between DNOs and prospective and actual DG owners on where problems lie and how the connection process can be improved.

The measures in RIIO-ED1 may help improve the speed and ease of connection for DG, but according to a number of sources, various issues remain currently. The rapid growth in solar PV over the last two years at both rooftop and utility scale (see section 3.1.6 below), shows that network charging *per se* is not a barrier to the growth of renewables at the aggregate level if other incentives are sufficient. However, connection can still be a barrier to particular DG projects for a number of reasons. Broadly there are two issues: connection charging and the connection process.

Owners of distributed generation also raise issues with the connection process, citing large variations between DNOs in how long they take to connect and in levels of customer service (Zavody 2013). A recent report by Cornwall Energy (2013) argues that the formal connection process could be improved by broader dialogue on options in advance of formal triggers in the connection process. This may be particularly useful because, while DNOs have a regulatory requirement to offer the least-cost connection, this is not always the least risky option or most appropriate for generators, who may need a range of connection options (Zavody 2013). In addition, it is worth noting that DNOs are required to obtain permission from National Grid before connecting DG, which can also cause delays (Ofgem 2012f: 3).

Overall, the picture for DG is improving but still uneven in on the ground. As incentives for generators have changed, DG has actually grown significantly and continues to do so. For example, Northern Powergrid has seen a doubling in the new DG capacity connected between 2011/12 and 2012/13 (Jones (2013). But networks are still struggling to accommodate such

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[19] Standard Licence Condition 15, Appendix 1, see: https://epr.ofgem.gov.uk//Content/Documents/Electricity%20Distribution%20Consolidated%20Standard%20Licence%20Conditions%20-%20Current%20Version.pdf

rapid growth. Section 3.1.6 describes recent experience with the growth of solar PV. Network constraints due to growth in distributed generation by wind farms also already exist in Scotland. In the Scottish Highlands and Islands, networks are widely constrained and wind projects are facing waits of several years for grid connection still (Community Energy Scotland 2013). The development of non-firm connection offers as a way to speed up DG connection (see the Plug'n'Play example in section 3.1.2 above) is a good idea in principle, but in practice how well they work for individual developers depends on the details of the offer.

The advent of the DG Forum is a good development but more 'work is needed to improve the transparency and predictability of grid connection processes and charges' (Cornwall Energy 2013: 4), and connection charging is unpredictable and opaque. DNOs are now beginning to provide formation on congested areas in the form of 'heat maps' for higher voltage parts of their networks, but these are still quite broad and non-site specific. There is no guarantee for renewable generators that they will have priority access.

A final point is that, at the low-voltage level, DNOs still suffer from a partial lack of visibility of micro-generation (mostly solar PV); while installers are supposed to notify DNOs according to the Engineering Recommendations[20] they still do not always do so, so there is no fail-safe mechanism in place that allows DNOs to fully understand growth and clustering in an area. This also applies to low carbon loads, i.e. electric vehicle charging and heat pumps (Ofgem, 2012f: 4). At present there is no requirement for installers or purchasers of such technologies to notify DNOs, although this is being considered at the European Network Code level.

3.1.5 Changes to the wider regulatory regime

In addition to the introduction of specific incentives for R&D and the treatment of DG, Ofgem started to make a number of changes to the wider regulatory regime. As discussed further in section 8 below, the regulator came under considerable pressure over the 2000s to reform regulatory frameworks so as to ensure that there was greater innovation to allow energy systems to decarbonise. In late 2008 Ofgem started what it called a 'root and branch review' of the overall regulatory framework for networks, called 'RPI-X@20' (Ofgem 2009b). The RPI-X@20 review led in turn to what Ofgem has presented as a new regulatory model for networks, called 'RIIO', standing for 'Regulation = Incentives + Innovation + Outputs' (Nixon 2010).

[20] Until 2102, ER G83/1, now revised as G83/2

The fundamental structure of RIIO is the same as that of RPI-X, i.e. it is price cap regulation, in which network companies finance investment through an allowed rate of return. However, some important changes were made to some aspects of the incentive, which Ofgem argues will accelerate innovation (Ofgem 2012a, Askew 2013). For electricity distribution networks, some changes to the regulatory framework were already evident before RIIO, especially in the last of the RPI-X price controls (DPCR5, 2010-2015), which was being prepared at the time of the RPI-X@20 review.

Changes were made in a number of relevant areas:

- *Length of price control* - In RIIO-ED1, the price control period will be lengthened from 5 to 8 years, explicitly in order to allow longer payback periods for more innovative investments that might otherwise be rejected under a five year period. At the same time, this extension increases uncertainty about what may happen within the period. A mid-term review has been built in, and there is also the possibility of 're-openers' if events (for example growth in low carbon technologies) diverge from expectations by a significant factor. These measures do not eliminate the greater risk for companies, but they do limit it.
- *Incentives affecting capex/opex balance* - From 2007, Ofgem introduced a new mechanism, the Information Quality Incentive (IQI) to try to address the problem of DNOs trying to overinflate allowed capex. This offered companies a higher share of efficiency gains the nearer their initial proposal was to Ofgem's final determination (for details see Jasamb and Pollitt 2008). However, it is likely that this mechanism is at best only partially effective at overcoming the asymmetric information and gaming problems (see Ofgem 2010c: 67). Thus despite the use of the IQI in DPCR5 (2010-2015), initial proposals for capital expenditure were up to 21% higher than Ofgem's final determinations (Ofgem 2009d: 35). DPCR5 also saw the ending of the distinction and separate mechanisms for capex and opex, with the creation of a single total expenditure (totex) category. In theory this should incentivise DNOs to identify the cheapest network solutions regardless of the opex/capex make-up. Finally, under RIIO-ED1, instead of additions to the RAV being made on the basis of actual capex, they are now deemed to be 70% of allowed totex. In principle, this means that the link between capex and the RAV is weakened, and that the incentive to skew actual spend towards capex is removed.
- *Engagement with customers* – Partly on the basis of experience in airport regulation, network companies are required to engage much more fully with existing and potential future customers, in order to produce more clearly justified initial investment proposals. This includes forecasts of the uptake of low-carbon technologies (see Section 3.1.6 below). In

practice, in many cases 'customers' will be represented by suppliers, and this raises the question of how far the latter really do represent users or their own commercial interests.

- *Output targets and incentives* - partly in response to concerns about potential underinvestment, the 'regulatory contract' (i.e. what is to be delivered in return for allowed revenue) has been increasingly specified over time (Tutton 2012a). Output incentives (i.e. penalties and rewards) associated with performance targets for network quality and customer satisfaction, along with the requirement for asset health indicators to be developed, were introduced in DPCR5 (see Figure 2 above for Ofgem's assessment of the potential impact of these on rates of return). These outputs incentives have been strengthened in RIIO, although the incentive most related to DER is relatively small.[21]
- *Treatment of losses* - Losses in electricity distribution are an important source of additional cost in the system. Transporting electricity over long distances involves loss of energy in the form of heat. Losses are greater at lower voltages, so most losses are concentrated in distribution rather than transmission systems. Over the 2000s, losses in the GB distribution system were in the range 5-6% of electricity distributed (Sohn Associates 2009). It has been suggested that distributed generation could contribute to a reduction in losses, by providing local sources of power that do not have to be transported so far, although some modelling shows that as the penetration of DG grows, losses can increase (e.g. Méndez et al 2006). Woodman and Baker (2008), Shaw et al (2007), Cary (2010), Pollitt and Bialek (2008) and Cossent et al (2009) all called for a losses incentive on DNOs to help drive the connection of more DG. A general incentive to reduce losses was introduced in DPCR3 (2000-2005) and was included in the two subsequent price controls. In DPCR5 this was worth £48.42/MWh saved. Figure 3 shows the expected potential effects on the achieved rate of return, which is small but not negligible. However, in the RIIO ED1 process, this incentive has been dropped, mainly because in the absence of accurate metering at the end-points of the system, data on losses is very volatile and approximate (Ofgem 2012a: 27). In place of an incentive linked directly to the volume of losses, RIIO-ED1 has a licence obligation to reduce losses, subject to cost-benefit analysis of specific measures, and DNOs must publish their plans for losses reduction. There is also a discretionary award of £32m for innovative and efficient losses-reduction initiatives. However, there is no direction that these should include DG.

[21] There are six primary output categories in RIIO-ED1: safety; customer satisfaction; social obligations; connections; reliability and availability, and environmental impact. The last of these comprises outputs relating to the narrowly defined environmental impacts of networks, such as visual impacts, noise reduction and leakage of sulphur hexafluoride, and one relating to the wider issue of low-carbon flows on networks and the promotion of energy efficiency. This latter output is incentivised through a discretionary award. For electricity distribution networks, this is worth £32million over the price control period

The potential effect of these changes on network investment and operation after 2015 is discussed in section 3.1.6 below.

In addition to changes to economic regulation, Ofgem and DECC set up a Smart Grid Forum (SGF) in 2010 as a permanent replacement for the ENSG working group on smart grids. Its membership is dominated by network companies but it also includes ICT industry, electricity supplier and consumer representatives. The SGF has played a number of coordinating and review roles, including developing a cost-benefit methodology for smart grids, developing scenarios for the growth of low-carbon technologies, and reviewing regulatory and commercial barriers to smart grid development. Importantly, given potential problems of interoperability and system architecture arising from uncertainty and the absence of system architect (e.g. Shaw et al 2007),[22] the SGF has developed a more detailed, technical account of smart grid functionalities under Workstream 3 (SGF 2011). There has also been discussion of the European Smart Grid Architecture Model at recent SGF meetings (e.g. SGF 2014b).

3.1.6 Innovation in network planning to 2023

The development of a R&D mechanism and the other changes to the regulatory regime in RIIO were intended amongst other things to increase the pace of innovation, including the move to smart grids. For electricity distribution RIIO-ED1, will not come into force until 2015 so it is currently impossible to tell how far they will do so.

R&D support mechanisms have quite clearly had an effect, with the LCNF in particular leading to a step change in levels of R&D activity by companies. Many interviewees were of the view that these developments, and especially the LCNF, have also had a significant effect on DNO thinking and culture.[23] They have allowed DNOs to work together with suppliers, ICT firms, renewable generators and consumers on concrete demonstration projects. They have engaged Board level interest in the smart grid agenda.[24] They have made DNOs aware of potential new commercial relationships and opportunities (for example, in demand response).

However, innovation involves not only research on and development of new technologies and practices and their demonstration in pilots, but also their successful deployment in network

[22] See sections 7 below for more detailed discussions of coordination issues.

[23] Deasley et al (2014: 29) report increased staff resources being allocated to innovation and organisational changes in UK Power Networks, for example.

[24] For example, meetings of the Smart Grid Forum, set up in 2010 now increasingly attracting senior staff rather than engineers

situations where they can be assessed and tested for a number of years in real-world conditions (SGF 2014). It is thus more about eventual outcomes than projects per se (Deasley et al 2014).

A key challenge for network innovation policy is thus now about how LCNF trials can be translated into business-as-usual network planning and operation under the regulatory regime. The RIIO-ED1 framework attempts to build in mechanisms to support this process. In order to qualify for the fast-track acceptance of business plans (a considerable incentive given the financial savings and reputational gain involved), DNOs had to set out an innovation strategy in their business plans, including evidence of how they will incorporate learning from LCNF and other innovation trials into business-as-usual.[25] Ofgem's guidance for what an innovation strategy should address was based on work by the Smart Grid Forum on particular functionalities to be achieved by 2020 and 2030 (SGF 2011). RIIO-ED1 also contains an Innovation Roll-out Mechanism to fund the roll-out of proven low carbon innovations, which DNOs can apply to.

Some new approaches being demonstrated in LCNF projects may be directly taken up more broadly, especially where they help ease constraints that are binding now. For example, UK Power Networks are likely to roll out non-firm connection offers that are currently being trialled in their Flexible Plug and Play trial for new wind farms in East Anglia.[26] However, the evidence on how far DNOs expect smart grid solutions, including those informed by LCNF trials, to produce savings in the 8 year ED1 period to 2023 shows that the wider application of such solutions is likely to play only a marginal role. Table 1 shows the forecast savings from smart grid solutions against BAU for 5 of the 6 DNO[27] parent companies' RIIO-ED1 initial business plans submitted in 2013, in proportion to total forecast cost of network operation and investment. On average, smart grid approaches were forecast to save less than 2% of total spend.

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[25] This requirement may be seen as compliance with Article 14/7 of EU Directive 2003/54/CE, which requires DNOs to consider distributed generation and energy efficiency as an alternative to network expansion.

[26] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Plug-and-Play-(FPP)/. See Deasley et al (2014) for a few other examples.

[27] The Business Plan for SSE PD does not include specific figures for such savings

Table 1: Expected savings from smart grid solutions in the RIIO-ED1 period (2015-2023)

Company	Total expenditure proposals in ED1 (£m)	Forecast savings from smart grid solutions over ED1 period (£m and as % of total expenditure)	
		£m	**%**
ENW	1,900	34	1.8
NPg	3,224	31	1.0
WPD	7,055	128	1.8
UKPN	6,726	111	1.7
SPEN	3,720	90	2.4
Total	**22,625**	**394**	**1.7**

Source: Ofgem (2013g), Ofgem (2014), Company Business Plans

Since savings from smart grids applications are effectively deducted from allowed revenue, low expectations of savings might be seen as return to previous attempts to game allowances. Certainly, in its draft determination on the RIIO-ED1 settlement, Ofgem takes the view that these expectations are lower than they should be, given that the LCNF itself will have cost £450 million by 2016, and the claimed savings resulting from projects (if they were all successful) were of the order of £2 billion (Ofgem 2014a: 30). The draft determination adjusts allowed revenue on the basis that it expects to see a further £400 million of savings from smart grids solutions, roughly doubling the level of ambition. Nevertheless, this will still represent only around 3.5% of total expenditure.

One reason why smart grid solutions are not expected to make many savings against BAU approaches in the ED1 period is that DNO business plans are based on forecasts in which low-carbon generation and demand technologies (i.e. solar PV, heat pumps and electric vehicles) grow only slowly before 2020. Anticipating the growth and potential clustering of LCTs is important because the costs of accommodating these on networks do not rise in a smooth linear way. Instead, there will be 'knee points' or inflections in costs at a network level as they reach thresholds beyond which reinforcement is needed (e.g. John Scott in evidence to the ECC Select Committee, ECC 2010b: Ev69).

In the past, Ofgem has tended to require the need for new network investment to be demonstrated before approving it and allowing the related capex to be added to the RAV. It has been widely argued that this implies that 'anticipatory investment' for the *potential* future use of low-carbon technologies ahead of need was risky for DNOs, and that a change in Ofgem's approach would be needed (Shaw 2012: 5932; Cary 2010: 79; Smart Grid GB/Ernst and Young 2010) under RPI-X.[28] In practice, all price control periods involve an element of load growth forecasting, but since no long-established methods for forecasting LCT growth existed, it is likely that risk-averse companies would be unwilling to undertake such anticipatory investment without a clearer signal from the regulator.

In 2010 DECC issued guidance to Ofgem's governing Authority that, according to the network industry association, the regulator 'should carry out its functions in a manner that will secure that an early start by network companies in identifying and planning necessary 'strategic' investments in electricity networks should take place before firm commitments from generators are required' (ENA 2010: 2-3). Following the RPI-X@20 review, in which it was decided to reject a more directive or coordinated approach (see below section 7), in RIIO-ED1 Ofgem is interpreting its appropriate role as one of delegating to DNOs the task of forming 'best views' about the long-term growth of low carbon technologies (LCTs), e.g. heat pumps, electric vehicles, solar PV, wind etc. on their networks. DNOs are required to present these views in their business plans, along with investment plans for accommodating this technology growth, and a smart grid development plan. This acknowledgement of the need to plan for the growth of low carbon technologies on the basis of scenarios and to approve investments made on that basis as efficient is the closest that Ofgem has come to approving strategic, or anticipatory, investment.[29]

Ofgem have gone for this relatively delegated model in the expectation that the ED1 period (2015-2023) will see relatively slow LCT growth, especially in the more challenging technologies of EVs and heat pumps, and can be seen as a preparatory period for ED2:

> *'The take up of low carbon technologies is predicted to increase significantly during RIIO-ED2 and RIIO-ED3…The RIIO-ED1 period represents an opportunity to start to deploy smart grid solutions and get prepared for the more radical network changes that may be required in the future' (Ofgem 2013a: 17).*

On this view, the focus for smart grids in the ED1 period should be on least- or low-regrets investments, rather than an immediate widespread rollout (Frontier Economics/EA Technologies

[28] This approach was analogous to the 'invest-then-connect' regime in electricity transmission now superseded by 'connect-and-manage', whereby constraint costs incurred as a result of new connections being placed in a 'full' network are socialised across the market
[29] Although as recently as 2012 DNOs were still seeking clarification of exactly how this will work (Ofgem 2012f: 3), and how to strike the correct balance between avoiding delays in investment and avoiding stranded assets (Ofgem 2012g).

2012). Another way of looking at this is that Ofgem sees the priority for ED1 as the *modernisation* of electricity distribution networks, rather than their transformation to facilitate the growth of low-carbon technologies.

DNOs broadly share this view. In developing their ‘best views’ for LCT growth, companies have been expected to draw on a number of scenarios produced by the Smart Grids Forum (EA Technology 2012), which are in turn based on scenarios in the government’s *Carbon Plan* (DECC 2011b) (see Figure 1, Annex 2). In these scenarios (EA Technology 2012: 22) for heat pumps, the ‘low’ case sees virtually no growth until 2018, and around 1 million installed by 2030. ‘Central’ and ‘high’ scenarios show much more growth, but only from 2020 onwards. The ‘low’ scenario for solar PV sees only a doubling in units installed between now and 2030, while the ‘high’ scenario shows more rapid growth but only during the 2020s onwards, reaching 16 GW by 2030. For electric vehicles, all scenarios in the set see major growth (i.e. above 1 million vehicles) only with fast-charging technology, and only from the mid-2020s onwards.

Within this framework, DNOs draw on the scenarios but also take into account the input of stakeholders in their regions.[30] Overall, the DNOs have tended to take a conservative approach, almost all adopting the ‘low’ or ‘medium’ scenarios (Table 1, Annex 2). It is clear that companies prefer to risk undershooting LCT uptake rather than overshooting, and it also appears that at least some take the view that even the Carbon Plan scenarios are unrealistically high.[31]

Forecasts about LCT growth are of course dependent on wider LCT policy and technology development, not only in the UK but internationally.[32] This point can be seen in the case of solar PV, where scenarios for growth which were constructed in 2011 already vastly underestimate the expansion of installed capacity not only because of the effects of the feed-in tariff but also because of module cost reductions driven especially by cost-savings in Chinese manufacturing. The ‘low’ scenario, which many networks had chosen in the development of their business plans, sees installed capacity rising to 1.95 GW by 2030, and in the ‘medium’ scenario capacity is 2.3 GW in 2020 rising to 6.64 GW by 2030 (EA Technologies 2012: 226-227). In fact, by

[30] To this extent, this resembles an endless game of pass-the-parcel: the government delegates network governance to Ofgem, Ofgem delegates decisions about LCT growth and anticipatory investment to DNOs, and DNOs delegate estimates further to customers, whose views are to some extent influenced by government policies.

[31] A senior representative of one DNO is on record as describing the Carbon Plan scenarios as “very ambitious” (WPD 2103b: 3).

[32] As Shaw et al (2010: 5932) put it: “In a privatised energy system with incentive regulation and minimal scope for anticipatory investment, networks will adapt their assets to new demand and generation patterns once they have reasonable certainty of what those patterns will be. Those signals are only conveyed via requests from market participants. Thus the signals to networks are passed from government (sometimes via the regulator) to energy users and to generators and then to the networks.”

January 2014 installed solar PV had already reached 2.75 GW (Figure 2, Annex 2), far outpacing even the 'high' scenario.

Solar PV growth was thought to be easily handled with existing networks, but partly because of clustering and partly because of the rise of utility-scale solar PV investments in the last 2 years, growth is running up against network constraints. In WPD's South-West and South Wales regions, the 33kV network is already voltage-constrained at summer minimum load (Cosh 2013). If all current utility-scale PV plans (~2GW) materialise, peak output will be equal to summer minimum demand in UK Power Networks East Anglian region as well.[33]

From a smart grid perspective, solar PV growth matters less than would the uptake of electric vehicles and heat pumps, both in terms of capacity requirements and in terms of opportunities for avoiding or deferring conventional reinforcement through smart network operation and demand side management contracting, However, the case of solar PV illustrates the problem of uncertainty that the future development of networks are facing. For example, if battery costs drop dramatically because of a technological breakthrough and/or economies of scale in manufacturing, a similar surprise could also occur in the EV market, for example.

At the same time, policy itself could also change. For example, the pathway proposed by the Climate Change Committee in 2010 as being needed for meeting future carbon budgets, is slightly higher than the 'high' scenario for EV growth used as a basis for RIIO-ED1 plans is slightly, and much more ambitious than the low-to-medium scenarios assumed by the DNOs.[34] Furthermore, existing carbon budgets may need to change if they are to be consistent with overarching targets. The acceleration of global emissions and updated knowledge of climate change processes summarised in the 2013 IPCC Fifth Assessment Report findings imply that, to have a 67% probability of reaching 2°C target under reasonable burden sharing arrangements, the UK should be aiming for an 95% reduction in 1990 emissions by 2050, and that the current 2050 target of 80% remissions reduction should be brought forward to 2032 (Barrett 2014).

To a degree, network companies are protected from the risks such uncertainty about LCT growth poses. Ofgem has proposed an uncertainty mechanism in RIIO-ED1 which works when

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[33] Interview with Dave Openshaw, UKPN, February 2014

[34] The Committee on Climate Change proposed a pathway involving a cumulative number of 240,000 electric vehicles in the fleet by 2015 and 1.7 million by 2020 (CCC 2010). The 'high' scenario in EA Technologies (2012) is 219,000 by 2015 and 1.63 million by 2020 (including cars and vans).

actual load-related expenditure (including on low carbon technologies) diverges from forecasts by more than 20%, through a “re-opener” that allows the revenue cap to be adjusted. Finally, there will be a mid-term review of RIIO-ED1 which may also reset regulatory parameters if actual and projected growth have diverged.

The problem with such measures is that they are *post hoc* methods for addressing unexpected events, and may involve considerable delay during which time the ability of networks to facilitate growth in LCTs lags behind policy and/or consumer demand. If the main objective in this area is to ensure that networks are not a barrier to decarbonisation and technological development, scenario and contingency planning should play a more central role.

A second reason why smart grid technologies and contractual approaches being trialled in the LCNF are not translating into changes in BAU network planning, investment and operation is a set of risks to do with learning-by-doing in real network situations (see also Ward et al 2012a: 54). As the chief executive of one of the DNOs put it:

> *“Most of the things that will need to change in order for the distribution networks to do the kinds of things to which you have referred already exist; it is not technology that is not already out there, but it is just not applied in the public networks in this country. We do not need to invent things that do not exist but we need to apply them and really understand how they would work. We are talking here about the public electricity supply network which needs to be absolutely safe. We need to understand how it would operate in reality rather than in a laboratory or test case.” (Phil Jones, Northern Powergrid, in ECC 2010b: Ev55)*

This situation presents some challenges given that, despite recent enthusiasm for LCNF trials, DNOs remain risk-averse (see also Deasley 2015: 31).

One type of risk, at the micro-level, is that individual technologies may fail in real-world network situations over a period of time, even if they have worked well in trials. This was initially the case with new plastics-based insulation for underground cables in the 1970s, for example.[35] This kind of risk may also apply to new contractual approaches (for example for demand side response or distributed generation to reduce congestion on particular sections of network) (e.g. Ofgem, 2012f, Ward et al 2012a), especially with households rather than commercial providers of demand side response, since the extent to which households will honour such contracts,

[35] Personal communication, Dave Openshaw, UK Power Networks

outside of trials, is still unknown. These risks expose DNOs to the possibility that these failures lead to a reduction in reliability, safety and other aspects of network performance for which they will be penalised either within output incentive schemes or through fines for failing to meet licence conditions. Since output incentives under RIIO are stronger and more extensive than under RPI-X, these risks may have actually been accentuated by the change in regulatory regime.

Second, even though they have trialled a technology or approach, companies (and the regulator) will not know fully how much these will cost in real-world network situations, especially because mature supply chains for equipment in many cases do not exist, and will not exist until demand scales up. Within the context of incentive regulation, if companies underestimate these costs in a price-control settlement, they will be penalised.

Finally, there are risks arising from potential problems with interoperability if DNOs adopt technologies and approaches from LCNF trials without any overall coordination by what some observers call a 'system architect' (see also Shaw et al 2012: 5932, Skillings 2010, Sansom 2010. IET 2013). The risk here is that particular assets may become stranded if they do not conform to future standards or are not interoperable with what become dominant technologies, a common problem in technology races with network externalities (Katz and Shapiro 1985).

3.1.7 Conclusions on economic regulation

The original RPI-X regulatory framework for networks was designed for a supply-oriented electricity system and did not incentivise innovation by electricity distribution network operating companies for the use of DER.

Starting in the mid-2000s, a number of changes have been made to this framework. Specific incentives for R&D have been brought in and expanded, most notably in the Low Carbon Network Fund, since 2010. Specific incentives for connecting distributed generation have been introduced and then removed. The overall picture for connection of DG is very mixed, with some connection waits still long in some network areas and rapid growth of connected DG, especially solar PV, in others. Connection charges still vary and are opaque.

Ofgem has also made a number of other changes to the wider regulatory framework aimed at accelerating innovation, while still retaining the basic price cap approach. There are no significant specific smart grid, active network management or DER output incentives in the new framework; rather a combination of efficiency and output incentives plus a requirement for smart grid plans is expected to produce innovation.

It is not yet clear what the result of these changes will be, as they come into operation only from 2015. However, anticipated savings from smart grid approaches and technologies involving DER remain very small (DNOs originally anticipated <2% of expected total expenditure, Ofgem has now required 3.5%). This may partly be due to remaining risks in transferring smart grid approaches from LCNF trials to real-life network conditions under mainstream regulation, but it is also due to the expectation that the growth of electric vehicle charging and heat pumps use will be slow before 2020.

Despite the slow pace of change in practice, there is some evidence that interest in innovation in DNOs has increased and has reached to the Board level. This may be because even the partial electrification of heat and transport implies a large expansion of electricity distribution network investment, even with smart grid approaches involving DER.

A final point is that while technological and commercial innovation is now on the agenda for networks, innovation in the institutional and ownership arrangements has remained largely unexplored. GB has 14 large distribution networks owned by 6 parent companies, several of whom are international infrastructure corporations. This ownership structure has evolved out of the original settlement at privatisation and the unbundling of networks in the late 1990s. It contrasts with the situation in many continental European countries, where there are large numbers of small, often municipally owned networks. Germany stands out, with 869 distribution operators in 2012, of which 794 had fewer than 100,000 customers (Pérez-Arriaga et al 2013). But Spain, the Czech Republic, Sweden, Italy, France, Poland and Austria each have over 100 distribution network operators, and Finland and Denmark are not far behind. From the point of view of innovation, these different ownership arrangements may have pros and cons. Small DNOs have few resources and arguably less financial stability than large ones, but social and environmental objectives may play a much greater role for smaller network owners, with much more potential proactive interest in innovation.

In a background paper for RPI-X@20, Pollitt (2009) explored the idea of competition in providing network services (and the possibility of multiple networks) at the local level, but was quickly criticised by the network industry (ENA 2009: 11). Competition for network services remains restricted to new network extensions, and there are only a handful of tiny independent DNOs at present.

3.2 Distribution network charging

As discussed in section 3.1.1 above, under economic regulation DNOs are set a revenue cap for a fixed period (previously 5 years; from 2015, 8 years). Once the cap is agreed, DNOs recover revenue by charging consumers of electricity through demand charges. These charges, known as Distribution Use of Service (DUoS) charges, are levied on suppliers who then pass them through to consumers. In addition, DNOs levy charges on and offer credits to owners of distributed generation intended to reflect how far this generation adds to or reduces the need to reinforce the network. DG owners pay both connection charges and generator distribution use of service charges (i.e. GDUoS).

In principle, the structure and level of charging is obviously relevant for DER, because this is how information on network costs can be signalled to electricity consumers and providers (i.e. it is currently the principal 'route to market' for DNOs to access demand side flexibility – see Ofgem 2013f: 14). In particular, a shift to a system in which demand flexibility and distributed generation supported lower-cost networks overall would require charging signals that indicated the value of that support (e.g. Ruester et al 2014: 3).

In this section and the following section I look first at charging for demand and then for distributed generation. Up until recently, both types of charging differed between DNOs, not only in level but also in structure, i.e. in the way the charges were levied. In 2000, Ofgem began the *Structure of Charges* project to try to harmonise the structure of charging (Ofgem 2000). This very long-running project finally resulted in a Common Distribution Charging Methodology (CDCM) for low-voltage and high-voltage customers (i.e. those with a <22kV connection) and an Extra-high voltage Common Distribution Changing Methodology (EDCM) for those connected at 22kV and above. The CDCM has been in operation since 2010 and the EDCM for electricity users has been in place since 2012. The EDCM for generators came into force in 2013. In governance terms, charging methodologies now fall under the Distribution Connection and Use of Services Agreement (DCUSA) code (see further discussion in section 7.2 below).

3.2.1 Charging for electricity demand

Table 2 gives an overview of distribution charging arrangements for demand (i.e. DUoS) as of 2014. The CDCM covers all customers connected at below 22kV, which comprises all but a few hundred customers in each DNO area. It applies to most consumers connected to high-voltage parts of distribution networks, and all low-voltage consumers (i.e. households and small businesses). Charging is based on a hypothetical network model, and is not locational or site-specific.

However, within the CDCM, the structure of charging depends on whether the consumer has half-hourly metering or not. The vast majority of households and small businesses still do not have half-hourly metering. For these users, suppliers are charged on the basis of the number of meter points (p/MPAN/day) and the volume of energy (p/kWh) they supply, which they then pass through to final users. Some smaller consumers are on a very basic form of time-of-use tariff, in which time-of-use network charging is passed through suppliers to final consumers. There is currently a maximum of two tariffs for this group: Economy 7 for domestic consumers, and off- and on-peak for small businesses.[36] In 2011, around 5 million households were on Economy 7, using 29 TWh of electricity. According to Elexon (2012), just over two million customers have their electrical storage and immersion water heating controlled remotely by radio teleswitching, although only a minority of these have dynamic real-time response. Total annual switched energy is 1.9 TWh, or around 0.5% of total electricity supplied.

Table 2: Electricity distribution charging arrangements for demand

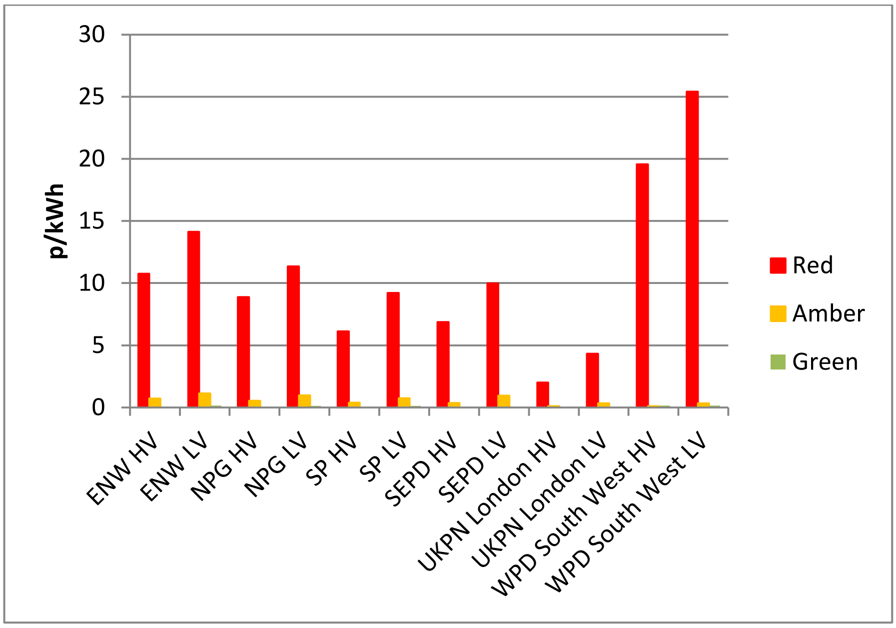
Type of charging	Type of customer	Metering	Charge unit	Channel	Site specific and locational
ECDM	All extra-high voltage (22kV+) and some high voltage (<22kV))	Half-hourly metered	• p/day • p/kVA/day • p/KWh charge within peak time band	Direct, or indirect through supplier	Yes
CDCM	All low-voltage and most high voltage	Half-hourly metered (generally >100kW)	• p/MPAN/day • p/kVA/day • p/KWh charges in three time bands • p/kVArh	Direct, or indirect through supplier	No
		Non-half-hourly metered	• p/MPAN/day • p/kWh (maximum of two rates)	Indirect through supplier	No

Source: Cornwall Energy, Ofgem

[36] The Economy 7 system was originally designed to shift peak time electrical demand, especially for space heating, to the night, in order to increase night time demand to match the output of nuclear power stations. In Scotland, peak demand often occurs at night due to the use of night storage.

Larger consumers, with loads in excess of 100kW, have half-hourly (HH) metering. For this group, there is a fixed charge (p/MPAN/day), a capacity charge based on the maximum import capacity as set out in connection agreements (p/kVA/day), and a charge for excess reactive power (p/kVArh). Capacity charges form a substantial and relatively fixed part of HH metered DUoS charges. In addition there are charges for energy (p/kWh) delivered in three time bands on a 'traffic light' system: i.e. 'green', 'amber' and 'red', where red charges apply during periods of peak demand to encourage load shifting (see Figure 4 for a sample of networks). The gradient in charging between these charges is currently very steep, with 'red' period charges up to several hundred times higher than 'green' period charges. In constrained areas, such as WPD's South West network, peak period distribution charges will be higher than the cost of energy supplied.

Figure 4: 2014 p/kWh charge for different time periods for HH metered customers under CDCM, selected distribution networks



Source: Energy Networks Association (http://www.energynetworks.org/electricity/regulation/distribution-charges.html)

A common charging methodology for consumers of electricity attached directly to parts of the network at above 22kV, known as the EDCM, was introduced only in April 2012, following a licence obligation on DNOs imposed in 2009 to develop such a methodology. These consumers are very large, individually identified loads, with charges tailored to their maximum contracted demand and location in the distribution network. The EDCM involves four charges for demand: a fixed charge (p/day), an import capacity charge (p/kVA/day), a separate charge for exceeding import capacity (P/kVA/day), and a unit rate charge for consumption of electricity during the peak period for the network, known as the super-red time band (DCUSA Ltd. 2014: 569). The fixed charge element in the EDCM is based on assets that they make sole use of. The actual level at which the tariff elements are set reflects not only the modelled costs involved, but also the gap between the sum of these costs and the share of the allowed revenue that the DNO can collect from EDCM demand customers. Charges are scaled up to fill any gap. This 'demand scaling' can make up well over 50% of EDCM revenue.

The EDCM has historically proven to be controversial and an area in which it has been difficult to reach agreement. The approach reached in 2012 has produced charging that varies significantly from year to year, and the methodology is already being reviewed by the Distribution Charging Methodologies Forum.[37] The allocation of reinforcement costs, the accuracy of locational signalling and of cost-reflexivity are all under scrutiny (Hodgkins 2014). In addition to the charging route to market for demand flexibility, DNOs can also contract bilaterally for DSR with larger HH-metered customers, through non-firm connection agreements. This market is currently of the order of a few tens of MWs.

Unlike in transmission, where the split between revenue raised from consumers and that raised form generators is set under regulation, in distribution this split varies across time and between DNOs. However, in 2011-13, about 60% of revenue was raised through domestic demand charging and 40% from non-domestic (Element Energy 2013: 25). About 80% of revenue was collected through unit (i.e. kWh) charges.

3.2.2 Charging for distributed generation

The vast majority of DNO allowed revenue is recovered from charges on demand customers, since distribution networks were primarily intended to serve these customers rather than generation users. Generation charging is not based on the collection of revenue to cover forward costs, but rather on the degree to which generation incurs or reduces or defers network reinforcement.

As discussed in section 3.1.4 above, the incentives for DNOs to connect distributed generation (DG) arise out of economic regulation. Incentives for owners of DG depend on electricity market conditions, and for renewable DG on deployment support policies, but also on DG charging. Ofgem's *Structure of Charges* project originally aimed at the introduction of a common set of system charges for DG in 2005. This proved not to be possible, so an interim arrangement was

[37] See http://www.energynetworks.org/electricity/regulation/working-groups.html

put in place in that year. Previously, generators had had to pay for any necessary reinforcement all the way up to the grid supply point, i.e. 'deep' connection charging, but no user of system charges. The new arrangement was 'shallowish' connection charges (Woodman and Baker 2008: 4529) based on the costs of extension of the network to connect the DG, and a splitting of any other necessary reinforcement costs between the DG owner and the DNO (see DCUSA Ltd. 2014: 826-841 for the most recent version).[38] At the same time, use-of-system charges (GDUoS) were introduced for new distributed generators.[39] Existing DG investments, which had been made on the basis of a system that involved 'deep' connection charges and no use of system charge, were exempted. In 2010, when the CDCM was finally introduced, this exemption was lifted, but pre-2005 connected DG customers received compensation for services and assets already paid for in their original deep connection charges.

The average level of connection charging is less relevant than the fact that charges can vary substantially according to circumstances, and the fact that the connection charging methodology is opaque to generators (see Cornwall Energy 2013 and comments from presentations at recent DG Forum meetings, e.g. Zavody 2013). This opacity is in part due to the complexity of the common connection charging methodology, but it is also because some projects may require reinforcement at high cost while others may not. If a number of projects cluster in an area, initial projects may be able to connect at low cost, but if a later project triggers the need for reinforcement, then its connection charges can be very high even with shallowish charging, and in some cases may derail a project (Cornwall Energy 2013, see also Ofgem 2012f: 4).

In practice, a significant proportion of DG comes from larger plant connected at voltages of 22kV and above, and is covered by the EDCM charging methodology (Table 3).

[38] In fact, some form of shallow charging for renewables, including DG, became required under the 2009 EU Renewables Directive (***2009***/28/EC). For renewables, the UK is rather unusual in any charging beyond immediate connection costs within the EU15, since most other countries (with the exceptions of Spain and the Netherlands for DG >10MW) have shallow charging (Cossent et al 2009).

[39] These charges applied only to newly connected generators, since existing generators had paid 'deep' connection charges and (following threat of legal action) were granted a 20 year exemption. However, the regulatory uncertainty arising from the initially retrospective change did not help create investor confidence.

Table 3: ECDM generation tariff elements

Component	Unit	Rationale
Fixed charge	p/day	Reflects direct operating costs and network rates
Export capacity charge	p/kVA/day	Reflects local and remote element of any reinforcement costs
Generation credit	p/kWh (negative)	Reflects local and remote element of any avoided/deferred costs (plus any transmission exit credits)
Excess reactive power charge	p/kVArh	Reflects average revenue per unit in the EDCM

Under the EDCM there is a charge applying to generation capacity (i.e. in p/kVA/day), and a credit (i.e. negative charge) based on the estimated extent to which generation contributes to network security, and reduces or defers the need for network reinforcement. However, the EDCM model only recognises DG benefits for predictable plant, i.e. thermal, and offers no credits for variable renewable plant on the grounds that they will not necessarily be exporting at times of system peak demand, or alternatively could be exporting at full capacity at times of minimum demand, and hence do not contribute to the need to offset network reinforcement. There is also a reactive power charge (i.e. in p/kVArh).

3.2.3 Conclusions on distribution charging

To an extent, distribution charging arrangements are supportive of the development of DER. Something like 50% of electricity demand on distribution networks is subject to network charges that give quite strong time-of-use signals to users, and some distributed generation customers are also rewarded for owning capacity that could contribute to reducing or deferring reinforcement.

However, this broad picture needs to be caveated in a number of ways. First, charging for *non*-half-hourly metered consumers is currently a very blunt instrument (see also Ofgem 2013f, 2013g). At best, there are only very broad incentives for Economy 7 and off-on peak users, and none at all for all others. Until there is widespread roll-out of smart meters, the scope for active demand side response by households and SMEs is limited (Ofgem 2013b). The roll-out of smart meters, which will take until 2020 to complete, on the basis of geographical area would be of greatest value to DNOs since it would give them much greater visibility of whole sections of the LV network. However, the roll-out is being led by suppliers, who have no particular incentive to proceed on this basis. Once data is available, DNOs will have to invest in capacity for analysis of this data. Little is known about domestic and SME capacity and willingness to deliver DSR, and there are a range of types of consumers within these groups. DNOs will in principle have access to half-hourly data from smart meters via the Data and Communications Company (DCC). Granular half-hourly data at the moment can only be used if there is a regulatory obligation placed on a licensed party (i.e. supplier or DNO) to make use or it--otherwise the customer must give consent. Therefore access to anonymised data for purposes of network planning or operation could require a change in licence conditions (and would also have to pass concerns about privacy and data protection). Additionally, when HH metering is available for all users, it is not clear that the demand charging methodology that is currently applied to HV and EHV customers will be appropriate for smaller customers, and changes to the CDCM will be needed. If charging continues to work through the supplier hub, then the ability of suppliers to pass through charging signals from DNOs in the context of the Retail Market Review arrangements, in which tariffs are limited, may also be an issue. These issues are discussed further in section 4.6.2 below.

Second, the degree to which charging methodologies give *accurate* signals about locational network conditions even for half-hourly metered customers is debateable, because these are based on network modelling with questionable assumptions. This is particularly evident in the case of the EDCM. It is possible that modelling will improve over time, but fully accurate signalling may never be possible.

Third, the EDCM does not reward variable DG at all for contributing to meeting peak system demand, while assuming that thermal DG always does. This is questionable as there is no certainty that a non-variable generator would actually run at times of high system demand or that a variable generator would not.

Fourth, charging still does not fully value demand side response. Time-of-use tariffs for HH-metered customers are charged only annually, and reflect longer-term costs associated with peak demand, based on estimated needs for future reinforcements. True dynamic time-of-use tariffs would require not only greater smart grid capabilities, but also a reform of the CDCM. The CDCM also does not necessarily capture all the value of DSR even in the longer-term. For example, the principle of cost-reflexivity in the CDCM for generation currently allows DNOs to pass through (some of) the capital costs of connection. However, where capacity for a new connection is made available by a third party (i.e. another customer) undertaking DSR rather than additional capital costs, there is currently no arrangement in the CDCM for reflecting these non-capital costs (Smart Grid Forum 2012). This means that the CDCM may have to build in more flexibility into charging.

Fifth, and possibly most importantly, even when all customers are metered, there is the issue of materiality. While charging methodologies can send consumers signals about the value of flexible or lower demand for networks, these are likely to be important only for commercial customers for whom electricity is an material cost, i.e. relatively energy-intensive users. For other customers, distribution network costs are only a relatively small proportion of total energy costs for many users. For example, distribution costs make up 16% of the average electricity bill for households in 2013. Even if energy costs themselves make up a significant share of expenditure (say 5%), the costs of distribution would be equivalent to only 0.8% of total expenditure for such users. Figures for small businesses will be similar. The implication is that for such customers, variation in distribution charges may have to be very large (i.e. critical peak pricing) to have a chance of changing behaviour,[40] or that demand response by such users in response to network pricing will have to be automated. This is especially the case since households and small businesses may also be receiving price signals for demand response from other actors, such as the system operator and possibly vertically integrated supplier/generator companies.

Some of these issues are now being reviewed by the Smart Grids Forum under Workstream 6, which is examining how incentives for domestic and small business customers to help avoid network reinforcement might work once smart meters are rolled out.

3.3 Network planning standards

A third aspect of the governance arrangements for electricity distribution networks with implications for innovative approaches using DER to minimise network costs, in addition to economic regulation and charging, is the security of supply standard for planning distribution

[40] For example, under the LCNF, Northern Powergrid's Customer-Led Network Revolution project is trialling time-of-use tariffs with smart meters with over 600 households and small businesses in Yorkshire and the North East. This trial is seeing peak shaving of around 10%, persisting over time, in response to a peak electricity tariff of around two and a half times the off-peak tariff. For distribution charging to produce an equivalent difference in electricity prices, on-peak charges would have to be around 16 times higher than off-peak charges. It should also be noted that the trial involved a self-selecting group of customers, who may have a higher response rate than the wider population of electricity customers.

networks, Engineering Recommendation P2/6.[41] DNOs are required to comply with ER P2/6 under standard licence condition 24 of the distribution licence, and it forms part of the Distribution Code documents. ER P2/6 does recognise the potential contribution of DG to network security and provides guidance on how to calculate implications for reinforcements (Cossent et al 2009: 1149). However, the Smart Grid Forum has also identified ER P2/6 as a potential barrier because at present it may exclude controllable demand, i.e. demand side response from the routes of supply that must be available for different size of demand groups (SGF 2012: 4), so that active demand side response may require a derogation from ER 2/6 (see also Ofgem 2012f). Electricity North West received such a derogation for its Capacity to Customers DSR trial under the LCNF (see ENW 2013)

Following the publication of the SGF report, the Distribution Code Review Panel instigated a 'wholesale review' of P2/6 in December 2012, which is expected to last several years before leading to the drafting of a new version (although there is likely to be a short-term fix to accommodate DSR not being in breach).[42] ER2 has not been properly reviewed since 1977, and in addition to the DSR point, the review will also look at other ways in which the regulation may need to change to recognise contributions to security of supply from a wider range of innovations, including energy storage and other 'smart/low carbon' techniques, including real-time thermal ratings (of lines, transformers and other equipment) and automatic/remote network reconfiguration.[43] While the update from P2/5 to P2/6 (which took place in 2006) does recognise the contribution of distributed generation to security of supply, the current review will also revisit the assumptions made then about how generators respond to faults and contingencies. In addition, while the analogous regulation for transmission, i.e. SQSS, covers both network planning and operation, ER P2 is solely a planning standard, and the review will also consider whether an operational dimension to a P2 upgrade is needed.

[41] This standard is the equivalent of the Security and Quality of Supply Standards (SQSS) for transmission networks. Both documents have been developed out of the predecessor P2/5 regulations developed in the 1970s and share common elements.

[42] http://www.dcode.org.uk/assets/images/P2%20Security%20of%20Supplies%20Open%20Letter.pdf

[43] Some LCNF projects

3.4 Summary for electricity distribution networks

Economic regulation, charging methodologies and planning standards are all important frameworks whose rules provide incentives for electricity distribution networks companies in relation to the development of distributed energy resources, including demand side response and demand reduction. The first of these frameworks is determined by Ofgem. Charging and engineering standards fall under industry codes, which are to a degree self-governing (see section 7.2 below).

Economic regulation has evolved since the early 2000s. Specific incentives for R&D have been brought in and expanded, most notably in the Low Carbon Network Fund since 2010. Incentives for connecting DG have changed over time, and the overall picture is mixed, with connection waits still long in some network areas and rapid growth of connected DG, especially solar PV, in others. Connection charges still vary according to network situation, and are opaque.

Following a major review at the end of the 2000s, a new economic regulatory framework was introduced by Ofgem, which will apply to electricity distribution networks from 2015. The new framework incorporates a number of changes, while still retaining the basic price cap approach. It is not yet clear what the result of these changes will be, as they come into operation only from 2015. There is some evidence that interest in innovation in DNOs has increased and has reached to the Board level. A Smart Grid Forum has been set up and is coordinating a significant amount of activity.

However, despite these changes at the level of regulation, organisation and discourse, there has as yet been relatively little change in practice. The upswing in distributed generation connections is the main change in outcomes so far. Looking ahead as far as 2023, anticipated savings from smart grid approaches and technologies in practice remain very small, partly because of expectations that the growth of electric vehicle charging and heat pumps use will be slow before 2020.

Existing distribution charging methodologies for electricity demand give quite strong signals on long-term peak network costs for half-hourly (HH) metered customers, who are responsible for about half of demand. However, these are not fully dynamic prices and so do not fully reflect the value of demand-side response to networks. Non-HH metered customers currently receive no signals of the value of demand reduction or response, although this should change with smart meter roll-out. For households and small businesses, real-time distribution charging is likely to have to be of a critical peak nature, or involve automated response, to become material. All these changes will involve modifications of code containing the charging methodology.

Finally, the engineering regulations required for security of supply used in the planning of distribution networks do not currently recognise controllable demand (i.e. DSR) and may need changes in other areas to allow use of dynamic line ratings, storage and automated or remote network reconfiguration. A review of these regulations is currently on-going.

From this review, it appears that *rules and incentives for electricity distribution networks are in a process of constant change, but also that this change is slow, and has as yet had limited impact on the demand side in practice*. There is a lot of activity of a preparatory or anticipatory nature on demand-side response, but as yet DSR plays a marginal role in networks and system balancing. Distributed generation has grown more quickly since 2010, although the degree to which networks have been able to accommodate this growth has varied.

4. Electricity transmission networks

The transmission networks facilitate bulk power transport at high voltages. On-shore transmission networks in GB are owned and operated by three companies: National Grid Electricity Transmission (NGET, part of the wider National Grid group) which covers England and Wales, Scottish Power Transmission Limited (SPTL) and Scottish Highland Transmission Limited (SHTL).[44] System operation is carried out for the whole of GB, including Scotland, by National Grid System Operator (NGSO), with certain services outsourced to a subsidiary of NG, Elexon.

The relationship between electricity transmission networks, (including interconnection with other markets and countries), distribution networks, demand side response and distributed generation is complex.

On the one hand, the optimal use of growing distributed generation, and especially variable renewable generation, will benefit from sufficient transmission capacity (and by extension,

[44] The voltage boundaries between the GB electricity distribution networks and the transmission network are somewhat arbitrary. In Scotland, 132kV lines form part of the transmission system whereas in England and Wales they form part of the distribution network. The distinction is to do with network architecture: 132kV lines in Scotland are characterised by parallel active circuits, whereas in E&W they are more radial in nature (NG 2013). It is for this reason that system operation is currently located at the transmission level.

interconnector capacity) to facilitate export from distribution networks through grid supply points. Demand side response (DSR) can be expected to grow if heat and transport are electrified to least some extent and as households and SMEs get smart meters, but at the same time, total peak electricity demand can be expected to increase as a result, implying the need for a transmission network with more capacity. The system value of DSR will be maximised if transmission network operators and the system operator have access to DSR services which are connected to the distribution network. Both TO and SO may also be able to access DSR directly through large industrial users connected directly to the transmission network. Thus DER are in a sense complementary to transmission capacity.

However, DG, DSR, distributed storage and indeed demand reduction are also a substitute for transmission and interconnection capacity. Insofar as they can balance the distribution system locally and reduce the need for imports from the transmission network, these distributed energy resources imply a smaller transmission system that essentially plays a residual role (see e.g. ECF 2009: 56 for an analysis at the Europe-wide level).

In any event, transmission networks and interconnectors are likely to need to both grow and change in any event, because of the need to serve growing amount of transmission-connected renewable generation in new remote locations (especially wind power) (e.g. Glachant and Ruester 2014).

Ideally, transmission networks would be of a size and configuration that optimised these interrelationships and minimised their costs, i.e. that they were no bigger than they needed to be. This implies that the key questions are:

- What are the rules and incentives for TOs to make optimal use of demand side resources (both directly and via distribution networks) and of distributed generation and storage?
- What are the rules and incentives for the SO to make optimal use of the demand side?

Similarly to the analysis for distribution networks, I explore these questions by an examination of rules and incentives relating to transmission networks arising from economic regulation, charging and network planning standards. I then go on to examine the frameworks for the System Operator. As noted in section 2 above, most of the development of distributed energy resources, almost by definition, will occur at the distribution level. A key question for transmission operators and the system operator is therefore how they interact with the distribution level. This issue is explored for distributed generation (termed 'embedded generation' by the TSO), demand side response and system operation in turn. A final section concludes.

4.1 Economic regulation

Electricity transmission networks have been regulated under the same incentive regulation framework as distribution networks since privatisation (see above section 3.1.1). Up to 2007, National Grid and the Scottish transmission operators (TOs) had separate price control reviews, but in TPCR4 (2007-2012) their regulation was synchronised. Since 2013, the TOs have been regulated under the new framework, i.e. RIIO-T1.

As with distribution network companies, there have been a mix of drivers for company behaviour under RPI-X regulation. TOs had an explicit incentive to bear down on costs (see above section 3.1.1). However, they also have implicit incentives to maximise allowed revenue, both because this makes it easier for companies to gain a higher rate of return, and because it effectively leads to a larger RAV, increasing overall yields for investors and adding to the value of the company. In TPCR4 (2007-2012) the initial proposals of the TOs were significantly higher than Ofgem's final proposals, which themselves saw a large increase in capex over previous price controls. NGET's initial proposals were 21% higher (Ofgem 2006a: 9). In RIIO-T1, this difference had reduced to 8%, but had not completely disappeared (Ofgem 2012d: 26). Potential distorting effects of the RPI-X regime on the balance between capex and opex, (which may affect the incentive to undertake innovative approaches to network investment and operation which maximise demand side solutions), were recognised in the move to RIIO, and in RIIO-T1, incentives apply to total expenditure (totex). As with RIIO-ED1, the price control for TOs is also now extended from 5 to 8 years.

Unlike DNOs, TOs have for many years operated more active network management systems, because of the different design of high-voltage transmission networks, which facilitate power flow management. Automated control of transmission networks goes back to the pre-privatisation period, with a national control centre established in 1962 (Lehtonen and Nye 2009: 2340). The Central Electricity Generating Board (CEGB) supported R&D on networks throughout the 1960s and 1970s, with overall energy R&D rising from 0.2% of turnover in 1958 to 2.2% in 1989. During the CEGB period, innovation was driven by the increasing demand for better power quality because of the increasing sensitivity of loads (including in industrial and commercial operations), with an increasing amount of power electronics on networks and rapid improvements in computer capacity and speed. According to Lehtonen and Nye (2009: 2340), by the late 1980s the CEGB had developed a 'substantial program of research on control', involving new software, stochastic system planning and reliability calculations and sophisticated demand forecasting, with the use of optical fibre for communications and monitoring being introduced.

However, capabilities in this area were drastically reduced on privatisation, with a dispersal of the R&D division amongst the new companies.[45] As with electricity distribution, by the mid-2000s, the low levels of R&D in TOs were acknowledged as a problem, and following the experience with distribution companies, an Innovation Funding Incentive was introduced in TPCR4 (2008-2013) (Ofgem 2006a: 66-67). The greater of 0.5% of allowed revenue or £500,000[46] was ring-fenced for R&D. In RIIO-T1 (2013-2021), reflecting the success of the LCNF, a larger innovation stimulus for TOs was introduced, more explicitly focused on the 'low-carbon future'. This included both a competition element with funding of up to £27m a year, and a use-it-or-lose it allowance, set at 0.6% of revenue for NGET, 0.5% for SPTL and 0.7% for SHETL. TOs have to provide 20% of the funding for projects. In 2013/14, the NIC funded two projects costing £18m. Again, as described above in section 3.1.3 above, there is also an innovation roll-out mechanism intended to support the transition of project approaches to BAU network planning, investment and operation.

There is an additional area where TOs, and in particular NGET, may have a particular incentive to expand the capacity of the transmission network to an extent that is not necessarily justified. This issue is to do with constraint costs.

Where transmission network capacity at a boundary is less than the peak output of all generators net of demand on that side of the boundary, there can be congestion, and generators can be constrained off. The main (but not only) problem arose with the extension of NETA to Scotland in 2006 in the form of BETTA, because of the large excess of generation over peak demand (over 20GW in 2013) north of the Scotland-England (Cheviot) boundary where there are four transmission circuits having a capacity of only around 2.4GVA (see for example, Newbery 2011: 13-14). This was exacerbated by the move to a 'connect and manage' regime for new connections as new wind capacity came on line (Scottish constraint costs now correlate pretty well with wind output).

[45] See Jamasb and Pollitt (2008) for a wider analysis of the fall-off in R&D in energy following privatisation
[46] The £500k floor was introduced because SHETL was such a small company.

Under the BETTA market system, while there are strong incentives to balance energy, there are only very weak incentives to balance the *location* of contracted generation and demand because constraint costs are socialised through the Balancing Services Use of System (BSUoS) charge.[47] Under the current arrangements, the system operator can accept bids from generators on the constrained side of the border to stop or reduce generation, but have to pay other generators on the other side of the border to increase generation. Constraint costs are therefore determined by the bid-offer spread in the BM, which can be well above £100MWh. By contrast, under the previous Pool market arrangements, constraint costs reflected the difference between offers made by the ultimately constrained plants and replacement plants in the day-ahead schedule. This difference reflected relative fuel costs and ranged from a few £/MWh up to a maximum of £15/MWh. Thus the value of relieving congestion is not absolute, but depends on market arrangements. Strbac (2010) and Baker and Chaudry (2010) argue that constraint costs under BETTA are around ten times higher than they should be.

This has implications for transmission network infrastructure in which the relief of congestion plays a major role, since it influences the justification for that investment in its benefit-cost ratio. The problem of constraint costs within a context of growing wind generation led to the government and Ofgem commissioning an exercise in transmission network planning (ENSG 2009) which projected the need for £4.7 billion of investment by 2020, and which is now being embarked upon. However, the extent to which this investment is actually needed is contested (Strbac 2010). In part this contestation is based on network planning standards (see section 4.3 below), but in part it is based on a view that, while congestion does certainly exist, constraint costs are artificially inflated by market arrangements, which in turn over-incentivises investment in transmission capacity:

> *"Unnecessarily high costs of resolving congestion will always make investment in infrastructure look relatively inexpensive and will result in generators opting for financially-firm access. Ultimately, however, this will lead to the inefficient utilisation of existing capacity and unnecessary transmission investment at a time when investment requirements are already at historic highs." (Baker and Chaudry 2010: 5)*

On this view, optimal investment in physical infrastructure to resolve congestion should be lower.

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[47] Note on suspected gaming of constraint costs and consequent legislation

Insofar as they can outperform the regulatory settlement on totex and the cost of capital, the TOs and their shareholders will benefit from the large increase in transmission infrastructure expenditure that is now planned, a large proportion of which is aimed at reducing congestion a cross the Cheviot boundary. A separate arm of National Grid is the system operator for GB, and is incentivised to balance the system in the most cost effective manner, minimising BSUoS, which as noted above, are set to recover constraint costs. Profits and losses in this incentive scheme are capped at £50 million. By contrast, NGET's allowed revenue under RIIO-T1 will be over £14.5 billion over 8 years. Some take the view that there is a conflict of interests here, i.e. that the rate of return that NGET can make on a much larger transmission investment outweighs any relative small incentive on the SO side to reduce constraint costs. However, it is also the case that BSUoS has no locational element, and so regardless of any perverse incentives, the SO arguably cannot do much to reduce constraint costs under current market rules.

In terms of the demand side, the whole approach to managing congestion on transmission networks rests in the short term on managing generation in different locations and in the long term on larger networks. Demand side resources, for example incentives to increase demand, are not being considered. In practice, in the case of the Cheviot boundary constraints, the imbalance of capacity and current peak demand is large, and current demand response might make only a small difference. But the current approach does not try to optimise the operation and planning of networks for the development of the demand side.

4.2 Transmission network charging

As with distribution networks, transmission network use of service (TNUoS) charging as main current mechanism by which TOs can signal the value of demand reduction or response to customers. TNUoS are set using a methodology which is governed by the Connection and Use of Services Code (Part 14). In total, TNUoS make up a relatively small part of the average electricity bill for households – around 4% in 2013, although they are more important for larger businesses, especially more energy intensive ones.

TNUoS are levied on both generators and consumers (via suppliers), but 73% of revenue collected via TNUoS currently comes from consumers.[48] In both cases, charging is locational, based on a methodology that models the transmission system and estimates the long-run marginal cost of adding an additional MW or generation or load at each node. Nodes are

[48] There are proposals to increase this share significantly, to lessen the share paid by generators.

aggregated to produce zones, and a tariff model is then developed to create zonal charges. There are 14 demand zones. Zonal tariffs reflect the implication of the balance of existing demand and generation for adding to either in each zone. Thus Scottish zones generally have low demand tariffs and high generation tariffs, while London has a high demand tariff and a negative generation tariff in 2013-14.

Demand TNUoS are then set using these zonal tariffs. Charges are actually levied on suppliers rather than final consumers. The form of charges is different for half-hourly (HH) metered and non-HH metered customers. For their HH metered customers, suppliers forecast their peak demand during the three half-hourly periods at least 10 days apart during which system demand is highest during the winter period (Triad) and a zonal £/kW tariff is then levied on this estimated demand. This is effectively a form of critical peak pricing. For non-HH customers, suppliers forecast their total consumption in the period 4 pm to 7 pm for all days in the charging year, and a zonal p/kWh tariff is levied on this consumption.

Suppliers cannot pass through the non-HH metered consumption charge to customers in a time-of-use tariff, so they tend to add it as a fixed cost spread across their customer base. This arrangement could obviously change with smart metering for households and SMEs. Suppliers can, however, pass on zonal Triad charges to larger, HH metered customers. To help some of their larger HH-metered customers reduce these charges, suppliers now commonly provide Triad warnings to large industrial consumers so they can try to manage electricity use in expected Triad periods. There are various estimates of this so-called 'Triad avoidance': Ward (2012b: 24) give a National Grid figure of 0.5-1 GW, while Martin (2013) provides an estimate of about 2 GW, and there are signs that this has increased somewhat in recent years.[49] Triad avoidance in itself has made prediction of Triad periods more difficult.

In terms of volume, Triad avoidance may currently be one of the largest forms of demand side response in GB currently. However, this is not the outcome of an explicit demand-side policy based on a sustainability aim, but rather arises from a principle of cost-reflexivity that is used to govern the charging methodology, i.e. TNUoS reflects the costs of maintaining a network that is sized for peak demand.

[49] e.g. http://demandresponseblog.com/2013/10/07/transmission-network-use-of-system-charges-triad-management-trends/

4.3 Network planning and operating standards

As with electricity distribution networks (see above section 3.3) an important factor in the design of transmission networks are technical standards, known as the Security and Quality of Supply Standard (SQSS). The SQSS originates from earlier standards that can be traced back to the 1940s. It is a largely deterministic system that specifies practice and design across a number of areas: generation and demand connections, supergrid transmission networks, system transient stability, voltage criteria for 400kV and 275kV systems, and operational standards of security of supply (National Grid et al 2008: 1).

The SQSS is therefore is an important driver of network capacity and cost. For example, as Sansom (2010) notes, the statement of need for the expansion of the transmission network by 2020 produced by the ENSG (2009) was based on the SQSS.

There are two inter-related arguments that the SQSS contributes to the transmission network being larger, and therefore more costly, than is necessary. The first arises from the fact that the GB electricity system has always had more generation capacity connected to the transmission network than is actually needed to meet peak demand. This is because of the need to have a (planning) capacity margin, firstly since a number of plants may be unavailable at any one time, and secondly because a number of plants may go off-line at short notice, and a degree of back-up is always needed. Because of this need to maintain a margin, historically the network has always had to accommodate any plant which wanted to connect. Up until 2009, connection was only possible until any upstream reinforcements had been made (i.e. 'invest and connect'), but since that date a new 'connect and manage' regime has been in place that requires TOs to connect immediately and the SO to manage the additional generation in place.

At connection, a new generator is given Transmission Entry Capacity (TEC) rights, which define the rights of generators to export power up to a maximum capacity (i.e. in MW) onto the transmission network.[50] As there is always an excess of generating capacity, combined TEC rights exceed peak demand. Where local combined TECs exceed local network capacity they create the potential for constraint payments.

[50] The scaling factor used in the GB SQSS for the TEC of conventional plant is 83% of their nameplate capacity, derived from the inverse of the plant margin (i.e. 1/1.2) (Strbac et al 2007). Scaling factor for wind in latest SQSS is now 70%, reflecting their lower availability, but this is very conservative. Various lower scaling factors have been proposed: e.g. 60% by National Grid, 30-40% by Strbac et al (2007) and 20% by SKM

The TEC concept has been criticised as an instance of how the approach to network planning is based on supply (generation) rather than demand. Baker et al (2010) argue that such network design rules “tend to provide sufficient network capacity to allow the simultaneous contribution of all generation to system peak demands (inappropriate as there will be far more generation connected to the network than there is demand to supply), suggesting that rather more network capacity is likely to be built than is actually required.” In this sense, even though it needs only to meet peak demand, net of embedded or distributed generation (see section 4.6.1 below), transmission network planning actually remains focused on generation. Strbac (2010: Ev 268) argues that: “present practice and thinking in the area of network access excludes demand. The role of demand in defining short and long access is not considered in any of Ofgem consultation papers.” This situation contrasts with that in the US where the Federal Energy Regulatory Commission introduced the requirement to consider demand response and reduction in network planning in 2007. Deferring or avoiding transmission investment is part of the benefit of the demand side. According to Watts and Metternich (2014:10), the New England ISO recently deferred transmission upgrades costing $260 million because of demand reduction. Two electricity markets in the US, PJM and NY ISO, have capacity markets in which demand side response contracts play a significant role and in which avoided transmission costs form part of the benefits (Hurley et al 2013), with PJM avoiding initially projected transmission projects worth over $3.2 billion in 2012 (Triplett 2013).

From 2012, under modifications to the SQSS (GSR009) requirements for capacity are split into a deterministic element relating to meeting demand and a cost-benefit element related to minimising costs. An interconnection allowance in SQSS (which will remain under GSR009) is in place across most of the network which is designed to ensure that the transmission system does not unduly restrict generation from contributing to demand security (Ofgem 2011: 10-11). In addition, the cost-benefit analysis depends on the value ascribed to avoiding the loss of electricity supply (i.e. the value of lost load, or VoLL) and on the risk of such an event, i.e. the loss of load probability, or LoLP).

The SQSS aims for a low LoLP by defining a set of events that the transmission system must be able to withstand that lead to the loss of one or more elements of the system (e.g. circuits). It therefore specifies a minimum degree of redundancy or headroom above peak demand required in networks. A second criticism of the SQSS is that this deterministic approach prevents the use of operational techniques for releasing network capacity as a more cost-effective alternative to building assets:

> *“There has been a clear trend at the international level of growing use of advances in various technologies that can release latent network capacity through more sophisticated system operation, including application of coordinated special protection schemes, coordinated corrective power flow and voltage control techniques supported by wide area monitoring, protection and control systems, application of advanced maintenance techniques, application of advanced decision making tools etc., including the use of various non-network solutions, particularly demand and generation. All these technologies have the potential to increase utilisation of existing network and substitute for network reinforcements. Although some of these methods are applied by the GB System Operator, the present deterministic standards and the regulatory framework are a barrier for taking full advantage of such techniques given the absence of incentives for network asset and alternative non-network asset based solutions to be compared on equal footing.” (Strbac 2010: Ev267-268)*

National Grid as system operator does already use active network management techniques to release additional transmission capacity (see for example SQSS Review Group 2011: 5 on the use of dynamic line ratings), but to a lesser extent than a full probabilistic cost-benefit approach would imply. In 2008, a fundamental review of the SQSS was launched to consider, amongst other things, a move towards a more probabilistic cost-benefit analysis approach to security of supply for transmission planning (National Grid et al 2008). However, after consultation, the scope of the review was scaled back, and fundamental principles so far remain in place (SQSS Review Group 2011).

Ultimately the difference between Strbac’s view and the approach of National Grid lies in how the trade-offs between constraints, cost of networks and loss-of-load probability are handled. For a given network capacity (and therefore capital cost of assets), different amounts of power can be transferred using different rules and techniques (e.g. Strbac et al 2013). The more conservative the management approach, for a given physical network, the higher the cost of constraints. The less conservative the approach, the higher is the probability of interruption and lost load. Optimising these two factors gives optimal power transfer and the most efficient use of the network (which may differ, for example, according to weather conditions). Strbac’s analysis above implies that the implied value of lost load (VoLL) in UK arising out of network planning under GB regulation is too high.

The SQSS does not specify a VoLL but it implies a very high figure. Historically, reliability incentive regulation for TOs has set VoLL at £33,000/MWh, which is much higher than in other countries. OFGEM recently commissioned a study by London Economics that estimated the average VoLL for residential/small commercial customers in GB to be a bit less than £17,000/MWh, which falls within the range of estimates available for VoLL in other industrialised markets. This figure is being used in the most recent transmission price control regulation and the capacity mechanism analysis for electricity market reform (DECC 2013a).

In practice, National Grid may still err on the cautious side of operational network management because, whatever the regulatory VOLL,[51] major transmission level outages incur not just regulatory penalties, but also important political and reputational impacts. For example, the last important transmission-related blackout, which led to power cuts for 250,000 covering significant parts of London in August 2003, led to political rows and accusations of underinvestment.[52] Such considerations means that National Grid remains resistant to embrace wholly probabilistic, model-based transmission planning, despite its use elsewhere in the world, including Chile, New Zealand and parts of Australia.

The SQSS rules tend to bear down on network capacity utilisation rates (i.e. total energy actually transmitted as a percentage of technical potential). Current GB transmission network utilisation is around 55%. Because of the growth of variable wind generation[53] this may fall below 25% by 2030 under BAU network management (Strbac et al 2013), although GSR009 modifications could lead to higher transmission utilisation, especially across boundaries where there is a lot of wind on one side of that boundary (Ofgem 2011).

The issue that then arises with very low utilisation rates is that a less frequently used transmission network sized for peak winter demand and with a conservative estimates of LoLP and how far wind and other generation can share capacity will become very expensive. User charges per kWh consumed or per kW demand may become very high. The supply driven approach that underlies the transmission charging model will begin to break down.

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[51] Value of lost load cannot be observed directly, but must be inferred indirectly via price elasticities or user surveys. VOLL also varies between types of user and duration, meaning that a single figure used for regulatory purposes will always be arbitrary. Roques et al (2005) cite UMIST data giving values that range from £1 million/MWh for large industrial users for outages of 1 minute, which fall off with duration rapidly, to around £1,000/MWh for domestic users for 1 minute outages, rising with duration to around £5,000/MWh for a 24 outage.

[52] See e.g. http://news.bbc.co.uk/1/hi/england/london/3190143.stm

[53] This problem arises because wind turbine peak output is reached relatively rarely, and for most of the time turbines are generating at below their rated capacity. Transmission capacity for conventional despatched generation is planned on the basis of the inverse of the capacity margin, i.e. a scaling factor around 83% of its TEC. Transmission planning for network connections to wind farms could have a much lower scaling factors. Up to 2012, the SQSS effectively applied a scaling factor of 60% to wind.

4.4 The System Operator and demand side response

NGET, the transmission network operator for England and Wales, is also now the System Operator (SO) for GB, balancing energy through the balancing mechanisms and ancillary services as well as managing power flows on networks. The SO is governed by economic regulation that provides an incentive to minimise system balancing costs, which include constraint costs (see above section 4.1). The demand side does play a role in this part of the electricity system, albeit rather minor.

To balance energy, the SO relies in part on the procurement of a variety of ancillary services that provide forms of capacity to aid balancing that can be brought in as gate closure approaches. These include short-term operating reserve (STOR), frequency response, fast reserve and fast start capacity, on which the SO currently spends around £330 million a year (Table 3).

Table 4: SO ancillary energy services costs 2012/13

Service	Cost (£m)	% of total
STOR (BM and Non BM)	91	28
Mandatory Frequency Response	71	22
Commercial Frequency Response	65	20
Fast Start	6	2
Fast Reserve (tendered)	17	5
Fast reserve (non-tendered)	77	24
Total	**327**	**100**

Source: National Grid 2013b

Note: Percentages may not sum to 100 because of rounding

Some of these services can be provided by demand side response by industrial and commercial customers, sometimes via aggregators, especially in reducing demand, as well as or instead of by generation. In theory, this source of balancing would be quicker than many types of reserve generation and in many cases should be cheaper. In practice, the amount and sources of demand side response contracted is partly determined by the technical requirements. Participation on the fast reserve market requires a large minimum offer and is a mix of hydro and despatchable plant. Demand response is found more on the STOR and commercial (i.e.

non-mandatory) frequency response markets. STOR requires a minimum offer of 3MW (which can be from more than one site), deliverable within 4 hours and lasting for at least 2 hours.[54] Frequency response from demand response has the same minimum offer, deliverable within 2 seconds, for at least 30 minutes.[55] Thus demand response has access to a little under half of the ancillary energy services market, but in practice provides far less than this.

As Ofgem (2010a) notes, there is no public data available on industrial demand side response for ancillary services (see also section 4.6.2 below), but estimates are of the order of hundreds of MW. According to IEA (2011: 40) demand side response contributed 445MW to STOR in 2010. In recent years, between a third and a half of STOR has been provided by non-Balancing Mechanism units (i.e. not by large power plants) (National Grid 2013c). Total contracted STOR capacity has been in the region of 2.5-3GW. According to Ward et al (2012b: 17-18), some three-quarters of non-BM unit STOR is estimated to come from on-site back up generation, with only one-quarter being 'true' demand side response, which amounts to around only 200MW. Estimates for demand side contributions to Fast Reserve and Frequency Response are 50-300 MW and 80-90 MW respectively (ibid: 18). These estimates corroborate with a recent survey of 19 firms, found only two involved in FCDM and six involved in contracting short-term operating reserve (STOR) (Pooley et al 2012).

The GB ancillary energy services markets are quite mature, and aggregators have operated in these markets for some time, yet the contribution of demand side response remains quite small, and marginal to the over electricity system. It is not clear that there are specific regulatory barriers to growth in this market. Ward et al (2012b: 21) argue that "a variety of considerations – technical, locational, availability, prospective reliability and scale", limit the size of the DSR contribution, but that National Grid "is clearly open to greater non-BMU participation". Martin (2013) argues that technical constraints (imposed by the SO) are a barrier and in some cases are unnecessary. Energy-intensive industries in the UK tend to argue that manufacturing processes are not very interruptible and so the technical potential of I&C DSR is not large (e.g. British Ceramic Confederation 2009: 2 – see also Element Energy 2013: 50-51). However, the experience elsewhere, for example in the US (e.g. Hurley et al 2013) where demand response capacity approaches 10% of peak demand (an equivalent to 5-6GW in GB), suggests that there is further unrealised resource.

[54] http://www2.nationalgrid.com/uk/services/balancing-services/reserve-services/short-term-operating-reserve/
[55] http://www2.nationalgrid.com/uk/services/balancing-services/frequency-response/frequency-control-by-demand-management/

In the current incentive scheme for the SO there are no incentives specifically for demand-side response. However, there is a discretionary reward for developing new and innovative ways of balancing the system. Following discussions with industry, Ofgem and DECC, National Grid has introduced a new Demand Side Balancing Reserve auction mechanism in mid-2014.[56] This will involve tendering for 330MW in 2014/15, 1,800MW in 2015/16 and 1,300MW in 2016/17, with DSBR offers de-rated by a factor of .75 (i.e. 440MW will actually be procured to cover a 300MW requirement etc.).[57] This mechanism may help stimulate growth in the role of DSR in balancing services. The new mechanism rules out participation by those who already have STOR contracts, so should be additional.

4.5 Interactions with the distribution level

Historically, interactions between the electricity transmission network and the distribution network were relatively simple; generation was largely transmission connected, and power flowed across transmission networks, onto distribution networks and then in a largely passive way to loads. This picture is starting to change. There is an increasing amount of generation connected to distribution networks, and at certain times this can actually start exporting onto the transmission network. At the same time, with the advent of smarter grid technology, including smart meters, DNOs may want to start contracting demand-side response to manage faults, avoid investment and so on, but find themselves in competition for that DSR not only with TOs but also the SO and suppliers as well. More broadly, if distribution companies move from being largely passive network operators to more active system operators, there are questions about how these two sets of actors will interact.

This section briefly reviews the issues and the state of policy and/or regulation in three areas: distributed generation, demand side response and system operation.

4.5.1 Distributed generation

Historically, the electricity system has been designed for a one-way flow of power from generators, across the transmission network into the distribution networks and on to loads. The transmission and distribution networks are joined at grid supply points (GSPs).[58] For each

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[56] http://www.nationalgrid.com/uk/electricity/additionalmeasures.
[57] Since new legislation in December 2012,[57] the four German transmission operators are now required to tender collectively for 3,000 MW of interruptible load, representing around 4% of Germany's peak demand (see e.g. http://www.tennettso.de/site/en/Transparency/publications/interruptible-loads)
[58] In England and Wales these are substations on the 400kV and 275kV networks that feed into the 132kV parts of the distribution networks.

distribution network these are aggregated into a GSP group, of which there are 14 in GB. However, even by the mid-2000s, the existence of distributed generation (DG) meant that at certain periods, there was net exporting of power across GSPs from some distribution networks back on to the transmission network. Since the 2000s, this export has continued to increase. Distributed generation is now around 10% of gross GB peak demand, and for GB overall, over a quarter of GSPs saw net export at some point, rising to 37% in Scotland. Six per cent of GSPs (10% in Scotland) saw exports even at the period of peak demand (National Grid 2013a: 24).

One issue with such export is that codes and licences are not defined in such a way that it is recognised and legitimised. Under the Connection and Use of Services Code (CUSC) applying to transmission networks, the definitions of both grid supply points and distribution systems did not recognise the possibility of such net exports. In 2005, one of the DNOs put forward a proposal to modify this definition under the CUSC so as to recognise this possibility, but the amendment was opposed by NGET and was rejected by Ofgem (Ofgem 2006b). The current transmission licence still defines the GSP as “any point at which electricity is delivered from the national electricity transmission system to any distribution system”, without mention of the possibility of export. At the same time, transmission network operators (and the System Operator) have no visibility of the availability of small distributed generation[59] and their potential contribution to meeting demand nationally, although according to DNOs DG connection requires permission from National Grid (Ofgem 2012f: 3). There is currently a proposal to modify the Grid Code and Distribution Code to improve notification of DG to TOs.[60]

A second issue is how transmission charging treats distributed generation. Transmission Network Use of Service (TNUoS) charges are paid by generators and suppliers (and some directly connected customers). For suppliers (from whom transmission owners collect 73% of allowed revenue raised from TNUoS), if they buy electricity from generators connected to the distribution network[61] this serves part of their demand, meaning that net demand met through power transported through the transmission network is lower. This provides a number of benefits to suppliers: first, they have to buy less electricity that is flowing across the transmission network and therefore they avoid the demand TNUoS charges on that electricity, and second, the distributed generators they buy the electricity from do not pay generator TNUoS charges (and may benefit from negative GDUoS depending on location and

[59] Where DG is deemed to be "large" it may have to enter into a contract with National Grid as the plant is deemed to make use of the transmission system. These agreements are more prevalent in Scotland and include BEGAs and BELLAs whereby the plant pays for transmission charges and maybe participates in central industry via the BSC.
[60] Grid Code Review GC0042; see NG (2013a: 14-15)
[61] This applies to non-licensable generators of less than 100MW not connected to the 132kV system.

technology), meaning that their electricity can be supplied more cheaply (National Grid 2013a). In addition they save on BSUoS. These benefits are known as ‘embedded benefits’ and have historically been shared between distributed generators and suppliers in the power purchase agreement by negotiation.[62] The value of embedded benefits is estimated to be around £27/kW in 2012/13, and on the basis of National Grid modelling this is worth £215 million in 2013/14 – around 8% of the annual TNUoS bill (*ibid*: 19).

These arrangements were recently challenged, for two reasons. One is that the move to BETTA in 2005 involved the re-classification of 132kV lines in Scotland as transmission. This meant that a lot of wind generation previously treated as DG then had to start paying transmission charges, unlike most wind in E&W. The same discrepancy applied to wind connected via offshore 132kV lines which were also classified as transmission. Interim arrangements were put in place which gave small Scottish and offshore generators a discount on TNUoS, which initially ran to 2008 and is now extended to March 2016. Meanwhile a Transmission Arrangements for Distributed Generation working group was set up to try to produce a more permanent (or ‘enduring’) solution, but it could not come to agreement.[63]

The second is that National Grid was seeking to change the basis of TNUoS from net to gross charging. The existence of embedded benefits is based on net charging, i.e. TOs charge suppliers for network use of services on the basis of demand at the GSP group with distributed generation netted off. NG was considering a move to a system where TNUoS are charged on gross demand and on DG, and there is then a discount applied to power that does not use the transmission system as with Scottish generators. This is in part because power generated in one location in a distribution network may be contracted in another location which is served by a different GSP, and so the contract relies on the existence of the transmission network. The immediate rational for National Grid’s position is the principles of non-discrimination and cost-reflexivity enshrined in code governance (because charging methodology forms part of the CUSC). However, the underlying issue is that discussed above – i.e. concerns about how to charge for a transmission system that is used less frequently as DG grows.

Following consultation, National Grid has decided to end the discount to Scottish generators connected at 132kV, but not to proceed with any formal proposals for gross charging until other developments (changes to improve the visibility of embedded generation to National Grid, and

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[62] Note that if suppliers (or indeed DNOs) have contracts for demand response reduction, they also save on TNUoS.

[63] The final report is available at: https://www.ofgem.gov.uk/ofgem-publications/55754/070723finaltadgworkinggroupreport.pdf

changes to transmission planning in SQSS that ensure more account is taken of embedded generation) have taken place.[64]

4.5.2 Demand side response

Demand-side response is a key potential distributed energy resource, but it has several different potential values to several different types of actor in the electricity system. The value chain in electricity comprises generation, transmission, distribution and retail supply. As a consequence of the disaggregation and separation of the value chain following privatisation, each stage involves actors who have different commercial drivers (to which must also be added consumers of different types as well as potential new actors such as aggregators and ESCOs). Each of these actors will potentially want to use DSR, for different purposes (Ward et al 2012b, Ofgem 2013e, SGF 2014a, ENA 2014: 11-13):

- Suppliers – for avoiding imbalance charges in the BM
- SO – for ancillary services and/or balancing
- Consumers – may benefit from Demand management facilitated by DNO investments; lower bills;
- DNOs – for constraint management, fault management and reduced or deferred reinforcements[65]
- TOs – for constraint management, fault management and reduced or deferred reinforcements

Moreover, each of these actors may be seeking to make use of DSR at different periods in the future, for different durations, sometimes at specific locations and under contractual conditions (Table 5).

As discussed above, there is already some use of DSR by some parties, especially the System Operator and some DNOs.[66] However, if the use of the DSR is to expand, the value of DSR services to different actors has to be communicated effectively to consumers of electricity, and these latter also have to be aware of the opportunities available and what the different options are. They must also be able to take up these opportunities, with the appropriate technology (Ofgem 2013e).

[64] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/

[65] Poudineh and Jamasb (2014) suggest the development of 'contracts for deferral' between DNOs on the one hand and providers of DG or DSR services on the other

[66] Ward et al (2012b) report that DNOs currently contract DSR of the order of a few terms of MWs with I&C customers, as a form of fault management or to allow deferment of HV network and/or substation reinforcement.

Table 5: Demand side response service requirements

	Energy trading/portfolio balancing	Constraint management (system normal)		Constraint management (system abnormal)		Balancing services
	Energy supplier	**DNO (pre-fault: static)**	**DNO (pre-fault: dynamic)**	**DNO (post-fault): instant**	**DNO (post-fault): planned**	**NETSO**
Planning time	Day ahead	Annual/long term 5 yr	Annual/long term 5 yr	Annual/long term 5 yr	Annual/long term 5 yr	3 months – 2 years
Contract duration	1 year/fixed against supply contract	Annual/long term 5 yr	Annual/long term 5 yr	Annual/long term 5 yr	Annual/long term 5 yr	3 months – 2 years
Geo-specific	No	Yes	Yes	Yes	Yes	No
Dispatch notice	1-7 days	Annual – quarterly	½ - 4 hours	No notice	½ - 4 hours	6 min – 2 hours
Confirm available	n/a	As above	28 days+	Annual	Annual	Week ahead
Duration	½ - 2 hours	2 – 4 hours	2 – 4 hours	<8 hours	<8 hours	½ - 4 hours
Penalty	System pricing	Yes	Yes	Yes	Yes	Yes
Payment	Utilisation only	Utilisation only	Availability and utilisation	Availability only	Availability and utilisation	Availability and utilisation
Criticality	Low	Moderate	Moderate	High	High	High
Driver	Commercial	Operational/commercial	Operational/commercial	Operational/commercial	Operational/commercial	Operational

Source: ENA 2014, Table 2, p. 13

Two major issues arise. One is the ‘route to market’ for industry participants, and in particular whether the current principle of the ‘supplier hub’ for households, whereby all interactions go through the supplier will apply, of whether DNOs, TOs and the system operator might have a bilateral relationship, perhaps through an aggregator (see KEMA 2011, Ruester et al 2014: 2).

A second issue concerns the prices offered to consumers for DSR services and what those prices do and do not represent. The underlying problem is about clarifying interactions between industry parties in situations where the use of a consumer’s DSR by one party (e.g. a DNO, or the SO) can have a knock-on effect for other parties, which could benefit or harm those parties. In other words, there are externalities in the DSR market. For example, DSR contracted by a DNO could have an effect on the SO’s attempt to balance the system after gate closure. Conversely, if the SO has contracted DSR as part of ancillary services, DNO and TO network planning could be affected. Suppliers could be forced out of balance by other parties calling demand side actions from their half-hourly metered customers (Ofgem 2013e: 21). As ENA (2014: 8) notes, under these conditions, ‘Competition for exclusive rights to a DSR resource may escalate costs associated with DSR services and limit the expansion of the DSR market, potentially resulting in the most cost effective solution not being implemented.’ At present these effects are negligible, but they could become more substantial with major DSR growth.

Within this context, it is important to note that modelling by Pöyry (2011) implies that the relative commercial value of DSR to other parties will almost inevitably be higher than its value to DNOs, implying that price signals for DSR given by DNOs will be weaker than those given by other parties, except in post-fault situations. The assessment concludes that ‘the requirements for reliability and the consequences of failure to deliver are such that commercial signals may well need to be reinforced or augmented by mandatory/enforced approaches which ensure the full benefits of DSR can be realised without risk to security of supply’ (ibid: 5).

There is currently a lack of information-sharing between different industry parties, and ‘little or no visibility of DSR actions taken across the system’ (Ofgem 2013g: 10). Overall, the lack of clarity on the route to market and on potential externalities in a complex market have increasingly been seen as increasing risks and a barrier in the long term development of DSR.[67]

[67] An additional complication is that the Retail Market Review has now restricted the number of tariffs that may be offered by suppliers, which may also affect a potential market in the household sector for DSR.

Demand side response has been on the policy and regulatory agenda for some time (see Ofgem 2010a for a history), but there has been little change in practice so far. In 2012 Ofgem published a ‘Smarter Markets Strategy’, which introduced a longer-term objective for electricity DSR, ‘to create a market environment that supports the efficient system-wide use of demand-side response, which has the potential to reduce bills for consumers, enhance security of supply and contribute to sustainable development.’

In 2013 Ofgem consulted on the regulatory and commercial context, and came to the conclusion that a new market model was not immediately required, but that a framework for DSR formalising interactions between parties was (Ofgem 2013g). There are a number of initiatives already underway to try to meet these challenges, including projects by Working Group 6 of the Smart Grid Forum, a proposed framework put forward jointly by the electricity DNOs and the TOs (ENA 2014) and a Flexibility and Capacity Working Group convened by Ofgem under the auspices of RIIO-ED1 to identify remaining issues that may act as barriers to the development of demand side solutions (Ofgem 2012f), However, Ofgem took the view that a separate process was needed, and has set up a new group to develop a framework with a number of elements, including: more analysis of system, operational and financial cross-party impacts of DSR; arrangements for sharing more information on use of DSR; common standards for base-lining, measuring and verifying DSR; and lack of clarity on who has responsibility to issue a dispatch signal and who should own and operate DSR automation equipment.

4.5.3 Systems operation

As distributed energy resources grow and smart grid and smart meter technologies evolve, the opportunities and technical possibilities for DNOs to actively manage networks, control power flows and voltage, solve short-term congestion problems and balance energy supply and demand locally also increase. Distribution network operators (DNOs) will potentially evolve into distribution *system* operators (DSOs). A range of questions then arise about the future roles of and relationships between such DSOs and the SO (ENA 2014: 9, Kane and Auster 2014: 68). DSOs will effectively sit between providers of distributed energy resources on the one hand, and the transmission networks and the national SO on the other (Ruester et al 2014: 3).

One broad issue concerns the regulatory frameworks for all network actors, i.e. DNOs, TOs and SO. These frameworks (and especially the framework for distribution) were not designed for a world in which DSOs exist), and are likely to need major changes.[68]

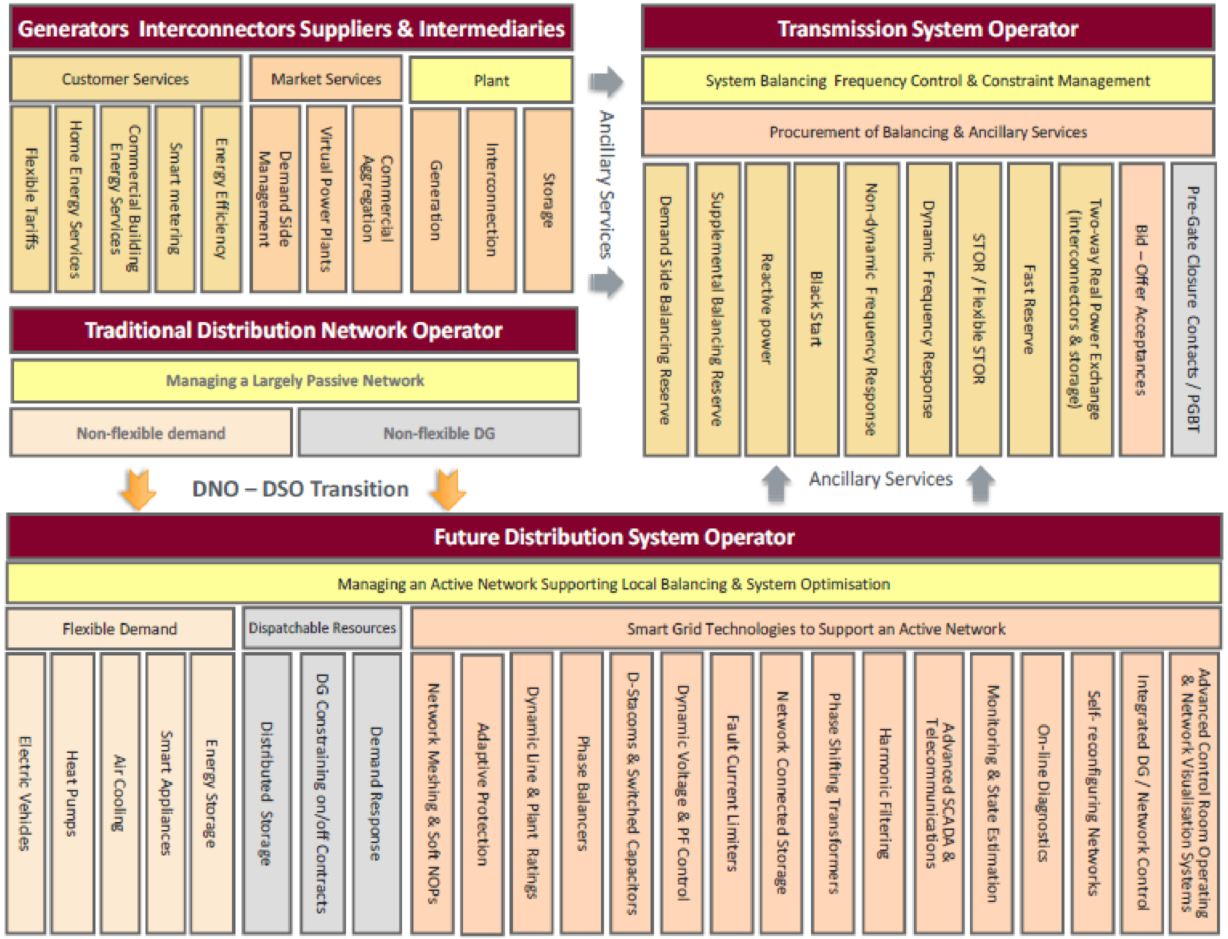
A second issue is about who takes responsibility for coordinating the interactions between distribution and transmission levels, which become much more complex (Figure 5). In theory the existing SO might take on this role, but it is not clear that the interests of National Grid, in both TO and SO roles, are aligned with the development of DSOs.[69] In late 2013, the Institute of Engineering and Technology produced a report arguing instead for the need for such coordination by a 'system architect' and emphasised the importance of a 'whole system' perspective (IET 2013). The Smart Grid Forum also calls for 'clear strategic direction' (SGF 2014: 26).

Ofgem and the Smart Grid Forum are starting to engage with these questions (Ofgem 2013c). Workstream 6 is to produce proposals on: definitions of a DSO; roles and responsibilities of industry parties at different stages of evolution of DSOs, commercial arrangements for DSOs, and regulatory barriers.

[68] One example is the use of storage and generation by DNOs for active network management. Because of the unbundling of distribution from supply in the 1990s, and the monopoly nature of networks, DNOs are prohibited from holding generation and supply licences. This separation is now reinforced in the EU Third Package (Ofgem 2013e). Using storage assets could be seen as generation from a regulatory point of view, although the legal situation is still unclear and there is a *de minimis* level of generation below which a licence is not required. In addition standard licence condition 29 restricts how much revenue DNOs can earn from non-regulated business (2.5% of share capital). DNOs could potentially get round these problems by contracting storage and generation services with third parties, although costs might be higher than if they owned the assets themselves). At present, while Ofgem has stated it is supportive of efficient use of storage by DNOs as a way of delivering outputs, and while there have been IFI and LCNF trials involving storage, legal uncertainty along with uncertainty about commercial arrangements and risk does represent a barrier. Use of generation above the *de minimis* is also prohibited.

[69] More active system operation at the distribution level might make the national SO job more complex or more simple, but it would a change from involve the substitution of negotiated or contracted interaction for direct control over the system. At the same time, a transmission network with more DG and DSR may well be a smaller network, with implications for National Grid's regulatory asset value and future growth.

Figure 5: Potential roles and relationships in a future energy system



Source: UK Power Networks

4.6 Summary

Under RPI-X and RIIO regulation, transmission operators have had similar incentives to those for DNOs. In addition, the apparent benefit to solving transmission network congestion problems is driven by the way that constraint costs appear under BETTA and the Balancing Mechanism, which some argue is too high, driving excess investment. So far, regulation has not incentivised TOs to consider demand-side solutions to network congestion problems.

As with distribution networks charging, transmission charging gives time-of-use signals to HH-metered consumers but not the mass of non-HH-metered households and SMEs. While the latter group may receive such signals in future, this would require modifications to the code governing charging. Materiality for this latter group will also be an issue, since transmission costs are small portion of total bills. For large consumers, whose charges are based on Triad consumption, signals are quite strong, and Triad avoidance appears to be increasing. But this charging arrangement, driven by cost-reflexivity rather than a DSR objective, falls short of full dynamic charging.

Transmission planning remains basically supply focused, with Transmission Entry Capacity concept privileging generation over demand response or reduction. Planning standards for transmission networks have also been criticised for gold-plating and inflating network costs. This debate comes down to trade-off between cost and security of supply, and therefore views on the value of lost load.

Demand response does play a small role in system balancing, via ancillary services, and this is set to increase with new reserve instrument. However, the total market for industrial and commercial demand side remains small in relation to other cases, such as PJM in the USA.

Exports from distributed generation (DG) onto transmission networks growing and becoming significant, showing how transmission capacity is both a complement for DER and at the same time is displacing centralised generation. National Grid is seeking to start charging DG more for the use of transmission capacity, but at present has shelved these plans. There is an absence of an overall plan for these interactions that is independent of the interests of TOs.

By contrast, Ofgem is taking an active and direct role in coordinating the development of a framework for demand-side response DSR, as it has become clearer that DSR relationships between one actor and a consumer could have spillover effects on other actors.

Overall, the relationships between DER, transmission capacity and centralised generating capacity are complex. Distributed energy resources, including demand side response, are both a complement to and substitute for transmission and interconnection capacity. However, thinking on the interaction between system operation at the national level with DSOs remains at very early stage. There are calls for a system architect, but so far no real response from Ofgem or Govt.

5. Gas networks

From the point of view of demand reduction, demand side flexibility and system costs, gas networks are somewhat different from electricity networks.

One reason for this is that gas is a commodity, which can be stored, and so the issues associated with variable generation in electricity do not arise. As a result there is less value to demand side flexibility in gas. The exception to this is in the case of periods of very high demand and import supply constraints, as during recent harsh winters during geo-political uncertainty.

The other reason is that it is likely that gas networks will become largely or fully redundant in future. The future of gas networks is dominated by the questions of how far heat is switched from gas to (decarbonised) electricity, and how far gas remains a fuel for electricity generation (e.g. Dodds and McDowall 2013, Arran and Slowe 2012, Redpoint 2010). In the government's strategy for the future of heating, use of gas in heating and power generation is expected largely to cease (DECC 2013b: 102-105). To the extent that this will be the case, from a system cost perspective, gas networks are the mirror image of electricity networks, since heat demand is expected to move largely from the former to the latter, or to district heating/CHP with heat networks. The issue of future peak energy demand and system cost is therefore central to electricity networks, whereas it is largely irrelevant for gas networks.[70] The only scenarios in which this is not the case are those in which parts of the gas networks are put to another use, such as transporting hydrogen or carbon dioxide for CCS. Both of these scenarios involve multiple technical hurdles and currently appear unlikely.

[70] There is some debate about alternative potential future uses of the gas network, including bio-methane injection, hydrogen transport in the low-pressure part of the network, or use of the network for transporting carbon dioxide from carbon capture sites (e.g. Dodds and McDowall 2013), but these remain conjectural.

At the same time, current demand is not putting pressure on the transmission network. As noted in section 2 above, annual gas consumption fell by around 15% between the late 2000s and 2012, due to a combination of the recession, reduced gas use for electricity generation and increased efficiency in the domestic sector. Winter peak demand, the more relevant metric for networks, has also reduced. National Grid data[71] show that winter peak daily demand during the 2000s was in the range 400-450 mcm/day, with the very cold winter of 2009/10 producing a peak of around 470 mcm/day. Since 2012, winter peak gas demand has been in the range 300-400 mcm/day. Moreover, as noted above future demand is not projected to rise. Ofgem's scenarios of gas demand for the purposes of security supply analysis are either broadly flat to 2030 or fall by more than 30% (Ofgem 2012h: 15).

This situation raises three questions. One is how the decline in network use is to be managed, and at what cost. Despite the fact that gas use by homes and small businesses is anticipated to decline and disappear by 2050, two major investment programmes are currently underway in gas infrastructure. One is the iron mains replacement programme (IMRP), which initially involved converting all iron pipes within 30 metres of any building to polyethylene pipes (HSE 2001). This programme has been in place since 1977 and is likely to continue until around 2020. The lifetime of polyethylene pipes has been estimated to be 80 years. The cost of the programme is considerable. Even with an amended risk-based approach, allowances for replacement expenditure to 2020 in the RIIO-GD1 price control were £6.7 billion, compared with only £2.6 billion for capital expenditure on reinforcement and extensions (Ofgem 2012b).
The other programme is the roll out of smart meters for gas over the same period. Of the smart meter programme cost of an estimated £10.5 billion in present value terms, smart gas meters and meter installation costs make up a larger share than electricity meters and installation. The anticipated combined cost of the meter and installation for a dual fuel home is £101.20 for gas, compared to £67.6 for electricity.[72]

Replacement pipes may well be retired early. Their funding by the consumer means that they will not represent stranded assets to gas distribution network operators and suppliers, but from a social point of view they will be so. At the same time, as regulated companies, the commercial values of National Grid Gas and of the gas DNOs lie with their regulated asset bases. Some form of exit strategy, involving a winding up of the companies, will be needed. One the one hand, these assets would in any case depreciate over time, but if gas use declines more quickly

[71] http://www2.nationalgrid.com/uk/Industry-information/gas-transmission-operational-data/supplementary-reports/
[72] Calculated from DECC (2014b: 35-37) assuming dual fuel savings split equally.

than the depreciation rate, they will become stranded. At the same time, as the IMRP and smart meter programme show, there may be need for interim investment to keep networks safe and useful. A second question raised by the wider background of falling gas use is how network use is to be charged, similar to the case of electricity transmission raised above.

While the long-term future for gas networks may be managed decline, there is also the question of how far current governance of gas networks supports or works against a more demand-side focused system.

Gas transmission and distribution network operators are subject to the same economic regulation that governs electricity network companies. Both gas transmission and distribution are now under RIIO regulation. They are subject to a basic totex efficiency incentive (i.e. they are allowed to keep a share of underspend/pay a share of overspend relative to allowed revenue).

They are also subject to a number of output incentives, including capacity availability drivers. Historically, network operators have used interruptible contracts with daily-metered large industrial and commercial users as a way to manage congestion and free up capacity if necessary. Such demand-side options were significant in volume - according to Newton (2010), gas DNOs had 1,175 such contracts covering 90m cubic metres, representing nearly 23% of UK peak demand. Such contracts offered lower transmission and distribution costs as compensation. However, over time and possibly reflecting reductions in demand during the economic recession, transport cost differentials between firm and interruptible contracts narrowed to negligible levels. In October 2011, the interruption regime for gas DNs was changed by a UNC modification,[73] and a more limited form of offering interruptible contracts through auction was instituted instead. However, recent tender results show that no bids are currently being made.[74] A similar change was made on the National Transmission System (NTS) in October 2012.[75] Thus network operation has moved *away* from demand-side mechanisms in recent years. Ofgem is now proposing a tender for demand-side response by large gas users in the event of an emergency, under a Significant Code Review, but this is on security of supply rather than network congestion grounds (Ofgem 2014b).

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[73] UNC Modification 90 – Revised DN Interruption Arrangement
[74] See recent years at http://www.gasgovernance.co.uk/int
[75] UNC Modification 239

Following the development of specific mechanisms for R&D in electricity networks, similar mechanisms, at a lower level of resource are also built into RIIO. In addition, there is also a small discretionary reward scheme for projects that are aimed at improving environmental outcomes.[76]

Network charging is governed by a methodology covered by the Uniform Network Code. GB gas transmission network charging is uniquely complex, involving auctioning of capacity, and an additional set of capacity and commodity charges for entry to and exit from the NTS. These charges are levied on shippers, who then pass them on to suppliers, who in turn pass them through to final consumers. Thus some of these charges are supposed to reflect peak use, and some energy use. However, the proportion of allowed revenue recovered from commodity charges has risen sharply in the last 10 years, and there is some concern that capacity charges are set too low in relation to the long-run cost of providing new capacity, and conversely that commodity charges are too high in relation to network use (Decker and Jones 2014). This situation might in theory imply that overall gas consumption may be lower than it otherwise would have been as a result. However, gas demand is fairly inelastic to price and transmission charges make up a small proportion of the average bill for small users (around 2% in 2013). Gas transmission charges are undergoing a process of review at the European level. The Agency for the Cooperation of Energy Regulators produced framework guidelines for harmonised tariff structures that were approved by the European Commission in late 2013. A detailed network code will be produced by the end of 2014. Partly prompted by European developments, Ofgem is also reviewing gas transmission charging, with objectives of increasing efficiency and security of supply. The relative levels and roles of capacity and commodity charges may be changed as a result.

Gas distribution charges are made up of four elements (Table 6)

[76] One such project, run by Scotia Gas Networks, involves using the energy released when de-pressurising gas from transmission to distribution pressures to generate electricity (see https://www.ofgem.gov.uk/ofgem-publications/49035/scotia-gas-2010.11-discretionary-reward-scheme-submissions.pdf). This project, which now has a capacity 7MW, could in theory be replicated at up to 60 other sites, with the potential to displace a medium sized power station. The project was part of a package of projects that won a small discretionary award under network regulation, but has received no other support. The electricity produced is not eligible for a CfD and may not be eligible for capacity payments – see http://alansenergyblog.wordpress.com/2014/05/13/time-for-some-turbo-expander-expansion/. It has also not yet been replicated.

Table 6: Gas distribution tariff elements

Charge	Location levied	Type of charge	Unit
LDZ System charge	Directly connected supply points	Capacity	Pence per peak day kWh per day
		Commodity	Pence per kWh
	Connected system exit points	Capacity	Pence per peak day kWh per day
		Commodity	Pence per kWh
LDZ Customer charge	Directly connected supply points	Capacity	Pence per peak day kWh per day
		Fixed (for supply points taking 73,200 to 732,000 kWh/year)	Pence per day
LDZ Exit Capacity NTS (ECN) charge	Directly connected supply points/ Connected system exit points	Capacity	Pence per peak day kWh per day
Administration charges		Fixed	Pence per day

Charges are set annually are paid by shippers who pass costs through to suppliers and thence to consumers. They are supposed to be cost reflexive, and provide a mix of signals about the costs of peak network capacity and gas use. However, with the exception of large industrial loads (which may in any case pay an optional LFDZ charge instead of the system charge), all these different charging elements tend to be rolled into one cost when passed through to final gas consumers. This may change with the roll out of smart gas meters, but this would again require changes to the code governing charging methodologies.

Finally, there is the issue of gas storage. The main debate on gas storage is about security of supply (e.g. Stern 2010). However, there is also some evidence to suggest that more gas storage could cut system costs by something of the order of £40-65m/year (Waters Wye Associates 2014) in savings in transmission infrastructure. Investment in gas storage is fully liberalised and decisions have to be made on a commercial basis. However, as storage is highly capital intensive and entails high levels of market risk, very little new storage capacity has been built over the period 1986 to 2010. This approach was revisited in Ofgem's gas security of supply review in 2011/12 and was not changed.

Overall, the existing rules and incentives governing gas networks are focused on efficiency and cost-reflexivity within a basic wider supply side approach. The incentive is for network companies to provide sufficient capacity but there has been a move *away* from using interruptible contracts on the demand side as one option for achieving this. While signals on the costs of the capacity are sent to shippers, these signals may understate peak capacity costs and are in any case seriously lost in the process of translation to the majority of final users.

6. Heat networks

Heat networks, providing district heating either from centralised boilers or combined heat and power (CHP) plants, currently provide less than 2% of the UK's heat demand,[77] although the cost-effective technical potential has been estimated at 14% (Pöyry 2009). In other countries, large central thermal stores used in district heating schemes have proven to be a useful type of distributed energy resource, for example helping to deal with wind variability in Denmark (e.g. Parbo 2014)

While construction of heat networks requires planning permission and compliance with regulations on digging up roads, the operation of heat networks is unregulated. [78] This is mainly because such networks are relatively small-scale and local, as opposed to the national gas and electricity networks.

The expansion of district heating and CHP is the UK is hindered less by specific regulatory barriers than by commercial considerations. To be commercially viable, schemes require a minimum heat load, and a customer base willing to sign long-term contracts for energy services. While technology costs are competitive with conventional heat and electricity alternatives, the transactions costs, including building the customer base, obtaining planning for local schemes and project management, are high relative to the scale of projects. Large energy companies have been reluctant to get involved. Instead, local authorities and city governments have often been investors, sometimes using their own facilities as a core heat demand. Again, city governments do not, strictly speaking, face any absolute regulatory barriers to developing heat

[77] https://www.gov.uk/government/policies/increasing-the-use-of-low-carbon-technologies/supporting-pages/heat-networks

[78] However, the district heating industry has drawn up proposals for a form of self-regulation – see http://www.heatcustomerprotection.co.uk

networks, but many lack the legal, technical and financial skills to develop projects, and are reluctant to take on the financial risk, although this picture is gradually changing.[79]

In Denmark, which has Europe's most extensive heat networks and in which around 80% of heat demand is met through district networks, the development of district heating was driven by *positive* regulation from 1979 onwards. All local authorities were required to draw up and implement detailed plans for DH/CHP. Since 1982, local authorities have had the power to require that consumers connect to a district heating network. CHP electricity was also subsidised and guaranteed a market.

The UK lacks such strong policies. There is a heat networks deliver unit in DECC that provides support and advice to local authorities, but financial support is limited to partial coverage of heat mapping and development costs. 'Good quality' CHP is exempt from the Climate Change Levy, but there is no other form of subsidy for localised heat technologies.

7. Network governance

The discussion above has examined the current rules in place governing energy networks in GB, and the incentives these rules produce for preventing or facilitating the move towards an energy system which is more oriented to the demand side. Two frameworks in particular are of central importance in influencing outcomes: *economic regulation* (i.e. previously RPI-X and now RIIO) and *industry codes and standards,* which govern connection, charging and network planning. The detailed rules and incentives described above arise out of these two frameworks. In understanding why the rules and incentives have arisen, and how they are changing, it is therefore necessary to understand how these frameworks are governed.

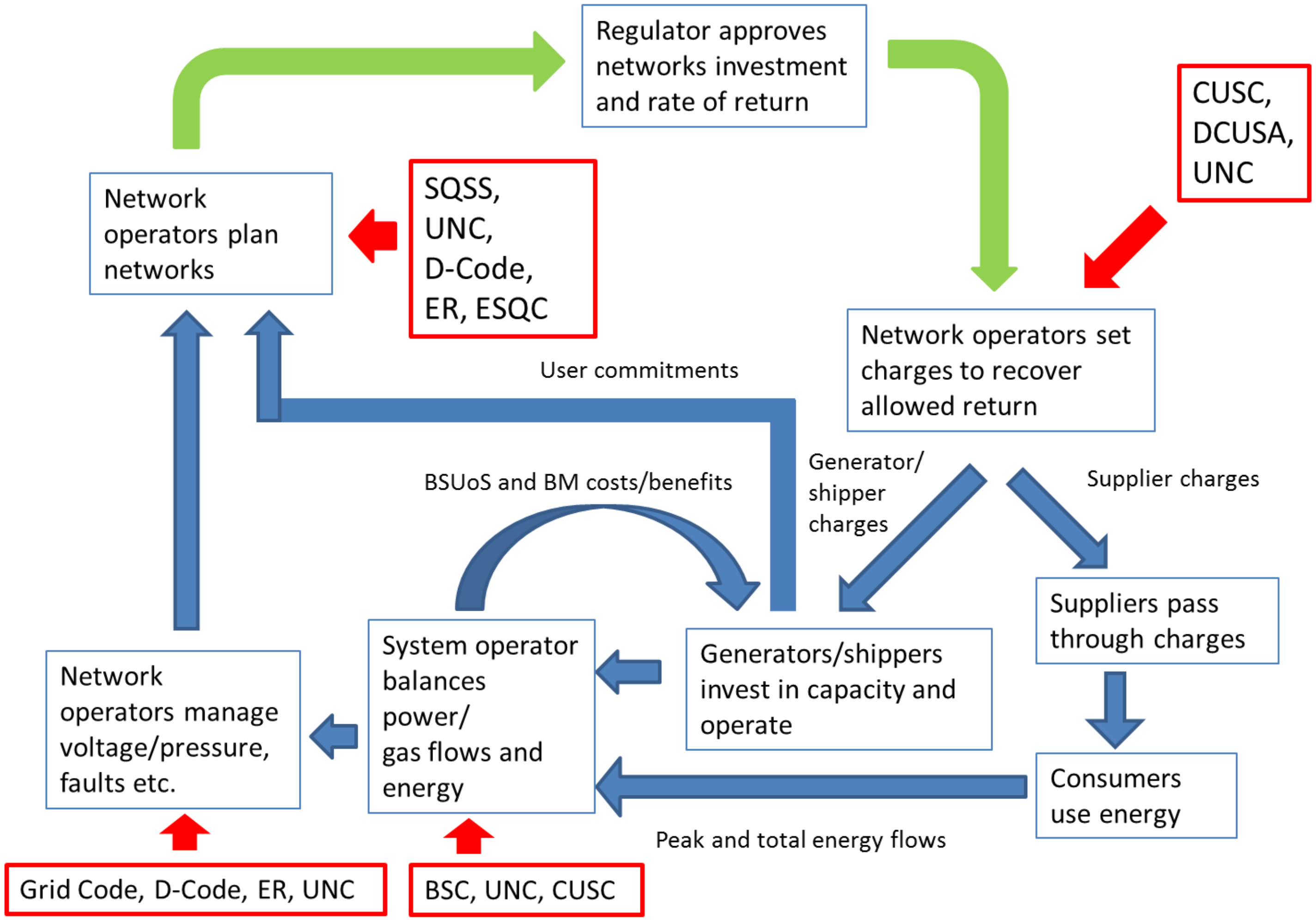
Economic regulation and codes actually interact in various ways, which are analysed in the next section. I then examine the way in which these two frameworks are governed, and how governance frameworks have evolved. Finally, I draw out some key themes in the governance of these frameworks that are important for the future of a sustainable, demand-side focused energy system.

[79] For more information see the Heat and the City project at http://www.heatandthecity.org.uk/

7.1 Interaction between codes and economic regulation

Economic regulation and industry codes in gas and electricity interact to shape the development of energy networks, as shown in Figure 5. The influence of economic regulation is shown in blue, and that of codes and standards in red. This figure can be interpreted as follows. Once the regulator has approved a programme of investment and allowed revenue in a price control period, network operators set charges for generators (shippers for gas) and suppliers using agreed methodologies laid out in the relevant industry code. Suppliers pass these charges through to final consumers. These charges in turn have some influence on the way generators, shippers and consumers act, i.e. in how much capacity generators invest in and how they run their plant, how much gas shippers seek to input to and offtake from networks, and how much energy consumers use (and currently for large industrial users, also what their peak usage is, i.e. triad). The resulting patterns of power and gas flows have to be balanced by the system operators in electricity and gas, and the costs of balancing are passed through to consumers, generators (in electricity) and shippers (in gas) as BSUoS in electricity and SO commodity charges in gas. The ways in which the balancing mechanisms work, including the rules for penalties for inflexibility and rewards for flexibility (i.e. cash-out), are laid out in the BSC and the UNC for electricity and gas respectively, while BSUoS charging is governed by the CUSC.

Figure 6: Economic regulation and industry codes



At the same time, network operators have to manage the resulting flows of power and gas on their networks in real time, aiming to meet outputs and performance criteria in their economic regulation and following procedures and maintaining system quality laid down by relevant technical codes.

As power and gas flows develop over the course of the price control period, as existing networks assets (lines, pipes, transformers etc.) age and companies carry out reinforcement, replacement or extension of networks, the ease with which network operators can meet their targets and, crucially, follow the technical rules and maintain the quality and security limits laid down in the codes and standards may change. With a rapid growth in demand, or in new generation, in particular locations on networks, the likelihood of faults occurring may rise sharply. Approaching the next price control period, network operators have a strong incentive to ensure that new reinforcement, replacement or extension is included in the price control review, as if they do not, they risk being penalised for failing to meet performance targets, and failing to meet conditions laid down in codes, and therefore being in breach of licence conditions, with not only legal but also commercial and reputational consequences.

As noted above, the effects of economic regulation on network operation, planning and investment interact with industry codes and standards, and the latter also have implications for innovation because of this interaction. Codes and standards specify, in a deterministic way, how networks must be operated and planned, given a particular pattern of generation and demand. The incentive to follow codes and standards arises from their link to licence conditions, in the sense that if companies do not adhere to codes and standards, they breach the licence conditions and risk fines, and ultimately loss of licence.

As described above, both these governance instruments have historically been designed to produce networks that facilitate a supply-oriented energy industry, and that in various ways present barriers to realigning the energy system towards demand reduction and flexibility.

7.2 Governance of codes

Codes and standards specify which practices are allowable across a wide range of technical and commercial operations, including terms of access and connection, charging methodologies, data reporting and management, terms and conditions of electricity and gas supply, voltage limits, acceptable fault risk levels and the treatment of variable renewable capacity. Table 4 shows the list of main codes and standards in electricity and gas.

Table 7: Industry codes and standards relating to networks

Area	Title	Description	Code objectives	Modification arrangements
Electricity distribution	Distribution Code (D-Code), including Engineering Recommendations	Technical parameters relating to the planning and use of electricity distribution networks	• Economical, secure and safe planning of network, • Facilitate use of network and specify standard of supply; • Establish technical conditions for entry to and exit from the network; • Formalise exchange of planning data; • Provide information to users of the network	• Can be proposed by any user • Proposals reviewed and voted on by Code Panel • Major proposals put out to public consultation • Final recommendation made to GEMA
	Distribution Connection and Use of System Agreement (DCUSA)	Covers commercial aspects of use of electricity distribution network services	• Efficient, coordinated and economical Distribution System • Facilitate competition in generation and supply • Compliance with European regulation	• Can be proposed by any party to DCUSA, a consumer body, the TSO, GEMA • Review organised by Panel • Block voting on corporate group basis, except DNOs which each have one vote • Ofgem makes final decision on changes proposed to restricted areas
Electricity transmission	Connection and Use of System Code (CUSC)	Framework for connection and use of high voltage transmission system and certain balancing services	• Facilitate effective competition in generation and supply • Compliance with European regulation	• Proposal can be made by CUSC Party, BSC Party or the consumer representative • Reviewed by CUSC Panel • Consultation with industry • Final recommendation to GEMA
	Grid Code	Technical aspects relating to connections, operation & use of	• Efficient, coordinated and economical system for transmission • Facilitate competition in generation and supply • Promote security and efficiency of transmission, distribution and generation	• Proposal can be made by GEMA, any user, any transmission licensee • Panel reviews, votes on, and makes recommendations to GEMA on proposals

		transmission network	• Compliance with European regulation	
	Security and Quality of Supply Standard (SQSS)	Sets out a set of criteria and methodologies for use in planning and operation of the transmission system	• Efficient, coordinated and economical system for transmission • Ensure an “appropriate level of security and quality of supply” • Facilitate effective competition in generation and supply • Compliance with European regulation	• Proposal can be made by a SQSS Panel Member, by GEMA, any ‘relevant interested person’ • Panel reviews proposals • Consultation with industry • Revised Modification Report and recommendation to GEMA
Electricity balancing	Balancing and Settlement Code (BSC)	Sets out rules for participating in Balancing Mechanism and for settling energy imbalance	• Efficient, coordinated and economical operation of the GB transmission system • Promote effective competition in generation and supply • Promote efficiency in implementation of balancing and settlement arrangements • Compliance with European regulation	• Proposal can be made by a Party to Code (except Elexon), Citizens Advice/Citizens Advice Scotland, ‘interested third parties’ designated by GEMA, the Panel (under certain conditions), a CfD counterparty, the capacity market Settlement body • Panel reviews and assesses proposals • Panel produces Modification Report and send to GEMA
Gas distribution, transmission and balancing	Uniform Network Code (UNC)	Defines the rights and responsibilities for users and operators of the gas transportation systems, and provides for all system users to have equal access to transportation services.	• Efficient and economic operation of the pipeline system • Secure effective competition between shippers and between suppliers • Provide incentives for suppliers to ensure that supply security standards are satisfied for domestic customers	• Proposal can be made by a gas transporter, a user, GEMA, and for changes to charging methodologies, a materially affected party • Panel reviews proposals • Consultation with industry • Revised Modification Report and recommendation to GEMA

Metering	Smart Energy Code (SEC)	Defines the rights and obligations of energy suppliers, network operators and other relevant parties involved in the end to end management of smart metering in Great Britain.	• Efficient provision, installation, operation and interoperability of smart metering systems at energy consumers' premises • Enable the DCC to comply at all times with the objectives of the DCC and to discharge the other obligations imposed upon it by the DCC License • Facilitate energy consumers' management of their use of electricity and gas through the provision of appropriate information via smart metering systems; • Facilitate effective competition between suppliers • Facilitate innovation in the design and operation of energy networks to contribute to the delivery of a secure and sustainable supply of energy • Ensure the protection of data and the security of data and systems	• Proposals can be made by any SEC Party, plus Citizens Advice and Citizens Advice Scotland, GEMA (under certain circumstances), the DCC and the Panel • During current transition phase, only urgent modifications can be proposed • Once transition complete, panel will review and if necessary refine proposals • Draft Modification Report prepared and consulted on • Final report goes to Change Board, made up of representation from all SEC Categories, plus consumers and DCC representatives • Change Board sends recommendation to GEMA

Source: Cornwall Energy, Code and Standard documents

Codes are particularly important in that they specify rules for access to networks, connection charging and use of system charges. Adherence to codes is required as part of standard licence conditions. It is possible for companies to depart from what is specified in codes and standards, but to do so, they must seek derogations. As discussed above, they also influence network planning, since the need for reinforcement will be justified or not in relation to network security and ranges of normal functioning as detailed in technical codes and standards.

Commercial codes have been established since privatisation,[80] but the engineering standards have their origins in the pre-privatisation post-War period.[81] Network codes have mostly worked well in the relatively stable environment since privatisation (although the cost-benefit basis of the degree of redundancy implied by engineering standards might be challenged). However, as the range of technical and commercial possibilities in the energy system changes, codes and standards should also evolve to reflect those changes, if the framework is not to become a barrier to innovation.

The current code and standards arrangements make them ‘living documents’, i.e. they can be amended through the modification process. This approach evolved partly out of the experience in the 1990s that the governance of the Pool Code, which was fixed, prevented amendment and policy learning. The modification arrangements for the different codes and standards are described in the right-hand column in Table 6.

Most industry actors are aware of the changes taking place that are opening up new opportunities for a demand-side focused approach to energy markets, and in principle, codes can be amended in ways that make them more supportive of a demand-side approach. However, there are two high-level aspects of code and standard governance that may slow this process.

First, code objectives are not aligned with government policy and Ofgem’s statutory duties in relation to sustainability (Brattle Group/Simmons and Simmons 2008, Davenport 2008, Baker et al 2011: 7). Instead, they still focus solely on the post-privatisation goals of ensuring effective

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[80] For example, DCUSA was established in 2006, replacing a number of bilateral contracts http://www.dcusa.co.uk/Public/DCUSADocuments.aspx?s=c. Distribution standard licence conditions specify that DNOs must apply connection charging as laid out in DCUSA https://epr.ofgem.gov.uk//Content/Documents/Electricity%20Distribution%20Consolidated%20Standard%20Licence%20Conditions%20-%20Current%20Version.pdf*

[81] The Security and Quality of Supply Standard (SQSS) was created in 1997, but originates in Central Electricity Generating Board planning and operating standards developed in the 1960s and 1970s. The equivalent for electricity distribution, Engineering Recommendation P2, also shares the same origins (see Kay 2012).

competition through non-discrimination, cost-reflexivity, promoting the welfare of consumers and consistency with European regulation (Table 6). The sole exception is the new Smart Energy Code, which does have an explicit objective to facilitate innovation for a secure and sustainable energy system. These objectives are linked to licence conditions and duties.[82]

In 2008, as part of a review of code governance arrangements, Ofgem commissioned an independent assessment of code governance, which noted that: "Differences between the code objectives and Ofgem's statutory duties means that the assessment of proposals takes place against one set of criteria while the decisions are made against a different set of criteria." (Brattle Group/Simmons and Simmons 2008: 4). Modification rules are based on licence conditions, which state that Ofgem's decision as to accept or reject a modification will depend on whether, in Ofgem's view, the modification better achieves the relevant objectives. Overall, this means that it remains difficult to make code modifications purely on sustainability grounds, at least without a Significant Code Review (see below).

In 2010, following the Code Governance Review, Ofgem introduced a requirement for panels to make an assessment of the carbon impact of a proposed modification,[83] but in practice the difficulty of calculating such effects means that the majority of these assessments either take the view that the carbon impact cannot be quantified, or that there is no impact. In addition, while there is the requirement to make this assessment, it is not clear how far assessments influence decisions.

The existing code objectives may work for or against innovation and a transition to a more sustainable energy system. In the case of network charging, the objective of cost-reflexivity has meant that HH-metered customers on electricity transmission and distribution networks have received clear signals about peak network costs, and has probably helped mitigate peak demand. However, cost-reflexivity may also penalise innovation. With long asset lives and network effects, energy networks have a strongly path-dependent nature. The cost of new connections, for example for DG, depends in large part on location in relation to the existing network, but this latter factor in turn reflects the history of the network. Cost-reflexivity as a principle (as opposed to the socialisation of costs) effectively makes new customers bear all the

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[82] In the 1989 Electricity Act transmission licence holders are given a duty to 'develop and maintain an efficient, coordinated and economical system of electricity transmission' and 'to facilitate competition in the supply an generation of electricity', but there are no sustainability duties. In the 2000 Utility Act the primary objective is the protection of consumers (meaning current and future consumers) and there are secondary objectives of economy and efficiency.

[83] https://www.ofgem.gov.uk/ofgem-publications/61741/ghgguidancejuly2010updatefinal080710.pdf

costs of transition from the past to the future. The partial socialisation of connection costs for DG has been imposed on the codes system from outside, in part by European regulation. Another example is the requirement for network codes to aim for non-discrimination. In markets with increasing returns (which characterises most energy markets), then non-discrimination will actually favour larger more established incumbents, and tend to work against encouraging new entrants and innovation.[84]

Ultimately, at present, while changes to Codes that increase the sustainability of the networks and other aspects of the energy system can be made, these changes can only be made if they also improve the economic efficiency of the system. A case based on sustainability alone will not be successful. Davenport (2008) gives the examples of two proposed modifications to the BSC to facilitate the growth of micro-generation (P213 and P218) that were rejected.

The second relevant aspect of code governance is that, while Ofgem has an ultimate veto power in certain areas, the evolution of codes is determined largely by the existing energy industry, and is dominated by incumbents. Generally, modifications can be proposed by any party to a Code. However, these proposals are then assessed by Code Panels, typically with detailed analysis where needed conducted by working groups. Draft recommendations are then put out for consultation with industry, before being revised and submitted to Ofgem, which makes the final decision.[85] Membership of the Code Panels is made up partly of elected members representing the energy industry and partly by appointed independents, plus GEMA and consumer representatives. The make-up of panels is determined by the constitutions of the Codes, and is constructed in terms of representations of different types of industry interests (i.e. network companies, suppliers, generators etc.).

Code governance has deliberately been placed in the hands of industry in order to provide stability for investment, since it means that the companies have a degree of control over rules that can affect their commercial interests. However, this arrangement has other consequences. One is that the modification process can be very slow (although under circumstances an urgent

[84] In other areas of energy policy, for example in obligations placed on suppliers, scale-related discrimination is well-established as a policy principle. The idea that non-discrimination will favour competition is based on a neo-liberal view of markets, whereas the idea that discriminatory intervention is actually sometimes needed to create and maintain competitive markets is more aligned to the Ordo-liberal policy paradigm developed in post-war Germany, and which was the basis for the Feed-In Tariff in renewable generation, as opposed to the UK's Renewables Obligation (e.g. Lauber 2004: 1406).
[85] Where changes have no significant impacts on parties other than the proposer, then under a 'self-governance' approach, they do not need Ofgem approval.

track can be followed) – one example is the review of SQSS, which has been ongoing for 8 years (see section 4.3 above).

A second consequence is that, in practice, industry incumbents and regulated monopolies have a dominant voice on Panels, and smaller, potentially more innovative companies are underrepresented (Table 7).[86] As the Institute of Engineering and Technology (2014: 11) points out, actors who will have an interest in network operation in a future integrated electricity system, including aggregators, micro-generators and community energy groups, have no representation on Panels.

Table 8: Code Modification and Review Panel membership, August 2014

Panel	Membership in 2014 (including Chair, excluding secretary)
D-Code	1 GEMA rep.; 4 DNO; 1 IDNO; 2 BM participating distributed generator ; 2 non-BM participating DG; 2 large users; 1 Big 6 supplier;1 consumer rep.; 1 offshore transmission system operator
CUSC	1 independent, 2 National Grid rep., 1 GEMA rep., 7 users (of which 4 are from Big 6 suppliers and 1 from Energy UK), 1 consumer rep.
Grid Code	5 National Grid, 1 GEMA rep., 4 large generators (of which 3 are from Big 6 generation arms), 3 DNOs, 1 nuclear generator, 1 Energy UK, 1 BSC Panel rep., Northern Ireland system operator rep., 1 'novel units' (i.e. renewables) rep., 2 SHETL
SQSS	4 National Grid, 2 SPTL, 2 SHETL, 1 DNO, 2 OFTOs, 1 independent generator, 1 GEMA rep.
BSC	4 independent (three of whom are ex-Big 6), 4 consultancy (one of whom is ex-Big 6, one ex-National Grid and one ex-DNO), 1 large IPP, 1 Big 6, 1 Energy UK, 1 National Grid, 1 consumer rep.
UNC	5 shippers (including 2 Big 6), 5 transporters (including 4 GDNOs and National Grid NTS), 1 consumer rep. + non-voting: GEMA rep. And Terminal Operators rep.
SEC Panel	1 independent (ex-Elexon), 2 Big 6 suppliers, 1 GDNO, 1 DNO, 2 small suppliers, 1 data management company, 1 meter supplier, 1 consumer rep., 1 DCC rep.
SEC Change Board	6 Big 6 suppliers, 1 GDNO, 2 DNOs, 2 small suppliers/ESCO, 1 data management company, 1 meter supplier

[86] This does not mean that the views of smaller companies do not enter into the formulation of a panel's view. For example, Davenport (2008) gives the example of BSC Mod. P194, which concerned making imbalance prices in the balancing mechanism sharper, which was put forward by NGET. Davenport (2008) argued that this modification would penalise renewable generators and smaller suppliers, who find it harder to remain in balance. However, in the event, the BSC Panel recommended not adopting P194, partly on grounds that it might affect smaller companies unfairly. In this case, it was Ofgem that decided that P194 would be adopted, against the Panel's recommendation.

A related issue is the ability of smaller actors to participate effectively in the process. Active, effective involvement in code panels requires deep knowledge, technical experience and significant resource. Large incumbent companies also have the resources required to deal with the complexity of Codes and modifications, whereas small companies struggle to keep up. The fact that Code Panels were not necessarily functioning in such a way as to allow smaller industry participants to participate fairly has was recognised in the fact that it has been considered to introduced a Code of Practice of Code Administration, which was supposed to reduce complexity and help smaller participants. It is not clear whether this has been achieved.

The only way in which the normal code governance process can be circumvented (other than changes required by primary legislation) is through Ofgem instigating a Strategic Code Review (SCR). The SCR process was an outcome of the 2008/09 Code Governance Review, which argued that major changes to codes required by policy changes were likely to get bogged down in the modification process, and that it was in any case more appropriate for a public body to initiate such changes. Under a SCR, Ofgem reviews the need for and the shape of modifications required to reflect a particular policy or regulatory decision. However, an actual modification proposal must then still go through the normal modification process. In practice, the SCR process has proven rather slow and cumbersome. The original expectation was that the whole process from inception of SCR to adoption of modifications would be under 20 months, but the first SCRs – UNC and BSC – have taken three and two years respectively to get to a decision by Ofgem, with actual modifications as yet to take place.

The combination of the factors discussed above, i.e. the absence of an explicit sustainability objective in codes and the advantages enjoyed by incumbents in the modification process, is likely to shape the nature of code evolution. This does not mean that relevant modifications will not be raised – the review of ER P2/6 to facilitate demand side response is an example (see above section 3.3). However, change will tend to happen only in ways and at a pace that incumbents and regulated monopolies drive. Changing codes in ways that are aimed principally at greater sustainability *and* which threaten the interests of incumbents is likely to be particularly difficult.

7.3 Governance of economic regulation

As described above (see especially section 3.1), the basic financial incentives for network investment and operation are set by the regulatory framework, which in turn is governed by the regulator, i.e. Ofgem, who in turn is accountable to the government (via the Secretary of State for Energy and Climate Change) and Parliament. Since privatisation the framework has taken the form of price-cap regulation, first under RPI-X and since 2010 under RIIO. The evolution of the regulatory framework for networks shows a mix of continuity and change, especially since the early 2000s.

The origins of the RPI-X approach lie in the debates over appropriate forms of regulation at the time of privatisation. The pre-existing model for privately-owned utilities at the time was rate-of-return regulation as used in the US. In late 1982, in the lead up to the privatisation of British Telecommunications, the Trade and Industry Secretary commissioned regulatory economist Stephen Littlechild to review different potential models for that industry (Moran 2003: 104-05; Stern 2003). Littlechild adhered to an 'Austrian' view of economics, in which the dynamics of market competition are seen as essential to revealing information about costs, and driving efficiency and innovation (Rutledge 2010a: 16-17; Helm 2003: 59). He believed that in most areas of privatised utilities, the need for regulation would be only temporary, and that competition would be established allowing the withdrawal of regulation.

However, for natural monopoly networks, this could not be the case, and the objective became how to regulate in ways that mimicked the workings of competitive markets as far as possible (Rutledge 2010a: 18-20; Helm 2003: 207-09). This led Littlechild to reject rate of return (RoR) regulation, which he saw as providing no incentive for improving efficiency. Moran (2003: 105) emphasises that Littlechild was also sceptical of US RoR regulation because it required the regulator to exercise discretion in making a detailed assessment of the asset base of the regulated companies and assessing what a 'fair' rate of return is, both of which open the regulator to capture (e.g. Newbery 2003: 3-4, Jamasb and Pollitt 2007).

What was originally intended to be a simple framework has evolved both in its formal practice and in the priority pre-occupations of successive regulators, and has become considerably more complicated. Immediately at privatisation, energy network companies received very generous allowed revenues, to ensure viability and attractiveness to investors.[87] Subsequent price controls were much tighter, focusing on bearing down on costs (Ofgem 2009a). Press releases

[87] See for example Moran 2003: 108 for the case of the gas industry

at the time of each price control announcement mentioned tariff reductions first. However, following power cuts (including one major outage in London in 2003), the focus shifted by the early 2000s to the need to invest to maintain quality of supply. Press releases now emphasised the level of capital expenditure that would be made to strengthen the networks. By the late 2000s, due to political pressure from Government (see below) Ofgem's focus moved on to decarbonisation.

Over the same period, the formal process of setting allowed revenues and an investment programme has also changed, becoming a lot more detailed. In Littlechild's original vision, parameters such as X in RPI-X could be chosen by the regulator almost randomly, and then actual expenditure by companies would over time reveal true costs. However, because of information asymmetries between regulator and companies, and the incompleteness of the regulatory contract, proposals for investment by companies turned out to be susceptible to gaming even in incentive regulation, and regulators could not necessarily tell the difference between cost savings made through efficiency gains, and cost savings made through neglect of infrastructure. Recognition of these problems led over time to the introduction of more attempts to prevent gaming (such as the IQI), more scrutiny of company proposals, From the mid-2000s onwards, there have been increasing attempts to make the regulatory contract more complete by specifying the 'outputs' that companies were supposed to deliver in return for a guaranteed revenue. There was also a growing acknowledgement that the regulatory framework disincentivised innovation, leading to the introduction of specific mechanisms for R&D, which became increasingly linked to the imperative of decarbonisation at the end of the last decade.

However, despite the fact that economic regulation of networks has changed since the 1980s, there is a strong continuity in that the core concern of the regulatory regime remains fairly short-term economic costs. This is in part due to the culture, skills and staffing of the regulatory institution as it has developed since privatisation. A common observation about Ofgem is the dominant role played by orthodox economists (e.g. Cary 2010: 62). This dominance should not necessarily produce opposition to the objective of innovation in itself, but it does mean that any regulatory support for innovation would have to be justified in terms of relatively short-term efficiency gains (as was indeed the case – see Mitchell 2008: 153). Given that orthodox neoclassical micro-economics is also essentially marginalist in approach, it also implies resistance to systemic, non-marginal change.

By contrast, early attempts to introduce a greater role for innovation, either for longer-run efficiency gains or for system change, came from outside of Ofgem's economist cadre. Thus, the initial stimulus to develop an R&D mechanism as a formal part of the regulatory structure came from two directions. One was external advocacy by a group formed in 1999 to raise the profile of DG and secure better terms for connection and generation (EGWG 2001), which later evolved into the DGWG. The second factor was internal advocacy from Ofgem's Technical Director from 2001 to 2007 and the only engineer represented at the Authority level. With his backing, two mechanisms to support applied R&D were developed in 2004 and introduced in the price control period that ran from 2005 to 2010. However, the introduction of R&D mechanisms was opposed by some within Ofgem,[88] who thought that if R&D were cost-effective, network companies would be already undertaking it.[89]

In the latter part of the decade, new external factors began to put pressure on Ofgem to facilitate greater and faster decarbonisation in networks. The wider context was a significant increase in public concern about climate change from early 2004, the Stern Review in 2007, the passage of the Climate Change Act in 2008 following a major civil society campaign, the consequent creation of the Climate Change Committee, the creation of a new government department bringing together energy and climate change and a Parliamentary Select Committee inquiry into future electricity networks (ECC Select Committee 2008).[90] A critical report by the now-defunct Sustainable Development Commission in 2007 questioned whether Ofgem had "kept pace with the climate change imperative and whether the government framework within which it operates is fit for the challenge of moving to a completely decarbonised electricity system by 2050", and recommended changing Ofgem's primary duty to reflect this imperative (SDC 2007: 6-8). Civil society groups joined in the criticism, arguing that Ofgem needed more staff with technical knowledge of renewables (Cary 2010: 62). Overall there was considerable political pressure Ofgem was under to become more proactive in engaging with the decarbonisation agenda.

In the most direct and formal way, this pressure came via several changes to the remit of Ofgem made by successive governments through legislation or guidance over the 2000s,

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[88] Giving evidence on the schemes to the Energy and Climate Change Select Committee some years later, one DNO chief executive argued that: 'It was a huge change four years ago when the authority [i.e. Ofgem] approved any form of mechanism for innovation. Up until then it had been very heavily focused on a statutory cost-reduction framework. A lot of water has flowed under the bridge since then, but at that time there were mixed views and great caution among some senior members of the authority. Some people were very hawkish, asking why they should be doing it…' (Phil Jones in oral evidence to ECC SC (2010b: Ev58)).

[89] This disagreement was reflected in the ambivalence of the language in the price control document that introduced the mechanisms: 'Ofgem has…considered whether there is reason to suspect market failure in respect of R&D funding by DNOs. While this is not clear cut, it is possible that the regulatory system is perceived to be such that it undermines the commercial incentive to R&D that the patent system provides in other sectors' (Ofgem 2004: 48).

[90] See Carter and Jacobs (2013) for a comprehensive account of this period.

apparently intended to increase the attention given to climate change and decarbonisation of the energy system, amongst other things. When Ofgem was created in the 2000 Utilities Act, its ‘principal objective’ was defined in legislation as protecting the interests of not only existing but also *future* consumers, with the intent that this created an obligation for Ofgem to consider long term sustainability in its regulation of the energy industry. This imperative was strengthened through the 2004 Energy Act which introduced the need for Ofgem to consider its contribution to sustainable development as a secondary statutory duty. In the 2008 Energy Act, the requirement to consider sustainable development was raised from a secondary duty to part of the primary duty. In the 2009 Energy Act, the language of the principal objective was altered, to clarify that the interests of consumers include the reduction of GHG emissions. In January 2010, the government issued revised guidance to Ofgem’s governing Authority, sharpening the requirement for Ofgem to regulate networks in such a way that they identified and planned for a low carbon future. Despite all these changes, the new coalition Government instituted a review of Ofgem in early 2011, and currently proposes to give greater direction to Ofgem through ‘Strategy and Policy Statements’ which are being introduced under an Energy Bill currently going through Parliament.

Institutionally, the role of outside groups continued with Ofgem advisory bodies such as the Sustainable Development Advisory Group and the Consumer Challenge Group influencing the implementation of RIIO. The latter in particular has had influence on the setting up of the LCNF. An important development was the establishment of a Sustainable Development Division within Ofgem in 2008, which has sought to engage with the mainstream price control process, with varying degrees of success.

The combination of political pressure, multiple re-setting of objectives and some more internal institutional champions of change did have an effect on Ofgem, which responded with a number of strategic reviews in the late 2000s. For the economic regulation of networks, the most important of these was the RPI-X@20 review which ran from late 2008 to 2010, and which led to the reformulation of regulation in RIIO. This review was premised on the idea that RPI-X had been largely successful in reducing costs and improving efficiency, but less so in meeting new challenges. Key figures in the review, especially Steve Smith, then Managing Director of Networks, emphasised the importance of the decarbonisation agenda as a driver for RPI-X@20. As the review proceeded, and the results fed through to a new framework, the focus arguably shifted more towards a more comprehensive incorporation of outputs into price controls, more emphasis on engagement with users of networks in the price control process,[91] contestability in network investment, and managing the need for higher capex as assets aged and a wave of new investment was needed (Tutton 2012a). At the same time, while RIIO explicitly seeks to address innovation and the possibility of major changes to networks, it also remains price-cap regulation in which cost minimisation remains a core objective.

This situation reflects the tensions between continuity and change currently at work in Ofgem. These tensions effectively arise from the trade-offs between minimising costs for current consumers and reducing costs (environmental and economic) for future consumers. Innovation in networks should produce a more future sustainable energy system and more efficient networks, but that innovation will require upfront investment. Under current arrangements, the cost (and associated risks) of that investment must be borne by some combination of specific users of networks (for example in connection charges), the wider generality of consumers and network company shareholders. How to handle these trade-offs, i.e. what the appropriate level of investment is and how costs and risks should be distributed are, ultimately, political questions. This fact raises some wider themes about how energy governance in Britain is organised.

7.4 The structure of energy governance and wider governance themes

In the previous sections I have argued that the rules and incentives governing energy networks, and shaping their practices in relation a shift from a supply-focused system to a demand-focused one, are set largely by two institutions or bodies of regulation – RPI-X/RIIO, and codes and standards. I have also described how in both these areas, changes in rules and incentives to encourage a shift to system with a greater role for distributed energy resources are possible, and to a varying degree, are beginning to happen, but also that there are aspects of these two governance institutions which may slow or block change.

The analysis in sections 7.2 and 7.3 asks why the rules and incentives for networks under economic regulation and codes have evolved in the way that they have. However, a wider question is why these regulatory institutions work in the way that they do, and whether a different approach to the structure of governance in the energy sector would manage transition to a sustainable energy system better. In this final section I offer some brief observations about these issues.

[91] Partly on the basis of perceived success of this approach in airport regulation.

Britain's governance system for energy is organised, at a high level, around the principle of delegation. Delegation works at different levels, both in the relationship between the government and Ofgem, and in the relationship between Ofgem and network companies. Delegation has some advantages, but it also has some disadvantages, especially from the perspective of managing transitions. Two important issues are information asymmetries and specifying outcome on the one hand, and coordination failures on the other. Partly in response to these problems, both the government and Ofgem have in practice begun to depart from the high level principle of delegation and acted to provide greater coordination in some areas. However, this is happening in an *ad hoc* way, without a clear strategy. At the same time, because the knowledge and capacity required for governance through delegation are not the same as those required for governance through coordination, there is a risk that such efforts will not be done well.

7.4.1 Delegated governance of energy in Britain

As described in detail in Flinders (2008), while modern states could not function without some degree of delegation, the British state has embraced the approach of delegated governance to an extreme, especially since major changes in the dominant economic policy paradigm in the late 1970s and early 1980s (see also Moran 2003).

This is readily apparent in energy policy (as well as other utilities such as in telecommunications, water and rail). In the pre-privatisation era, while energy policy had its own ministry in the central mechanics of government, many details and tasks of implementation were left to publicly-owned but quasi-independent corporate bodies, such as the CEGB, the regional electricity boards and British Gas. With privatisation, delegation was extended, and separation between central government and decision-making more clearly demarcated institutionally. The energy system was disaggregated and privatised. Between the newly created companies and the government, new regulatory institutions were created (i.e. first Offer and Ofgas, and then Ofgem). Where possible (generation, supply), markets were created and to a large extent, decisions about investment, service, prices etc. were delegated to actors in those markets, subject to oversight by the regulators. Where this was not possible, i.e. in monopoly networks, the task of making decisions about prices and investments was delegated to the regulator, who in turn has delegated some decisions (e.g. on charging) on to companies. Decisions about codes and standards have also been delegated largely to companies.

In Britain, the tendency has been to delegate energy decision-making substantively, leaving a great deal of discretion to the delegated party, rather than close direction of desired actions.

Delegation has worked largely by specifying desired outcomes, which, reflecting the shift to a market-led policy paradigm, have tended to be focused on competition (where possible) and efficiency. Delegation has also worked *primarily* through formally defined, arms-length roles and relationships, rather than through coordination and joint problem-solving, as is a more dominant approach in some countries (Hall and Soskice 2001).

There is a strong link between the market-led, or neo-liberal policy paradigm dominant since the 1980s, and the principle of delegation. This principle is based on a view that, while there may be market failures, government failures will tend to be worse, and the public choice analysis of government that emphasises capture, and bureaucratic and electrical interests that distort decision-making. Delegation to companies, managed by a technical body insulated from political interference, was argued to deliver better, more credible and stable policy in the long run, with favourable effects on investment and the cost of capital (Helm et al 2003). Similar arguments underpinned central bank independence, which was adopted in Britain in 1997.

Delegation in this manner has produced certain outcomes in networks. It has contributed to a low cost of capital and, in large part because of price-cap regulation being adopted, a reduction in network costs in the early post-privatisation era.[92] The period of initial privatisation and delegation (late-1980s through to the early 2000s) was also one of low gas and electricity prices, and few geo-political concerns about energy supplies. Energy policy was not only delegated, with the energy ministry being absorbed into the trade and business departments, but it was also effectively de-politicised. However, as politics re-entered energy policy, with rising concerns about energy security and climate change in the 2000s, and increasing debates about transformation of the system in the 2010s, it has become less clear that the nature of delegation that we have is the best arrangement (Kuzemko 2013, 2014).

To understand the nature of challenges now facing the delegatory mode of governance, it is useful at this point to break the analysis down into two levels: the relationship between governments and Ofgem, and the relationship between Ofgem and network companies. Both relationships are effectively principal-agent problems (Tutton 2012a).

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[92] Although, as discussed in section 4.3 above, some have disputed the cost-resilience trade-off.

7.4.2 The relationship between government and Ofgem

The relationship set between government and the energy regulators at privatisation was a somewhat contradictory one. Moran (2003) describes how on the one hand, the RPI-X framework proposed by Littlechild and subsequently adopted attempted to impose rules on regulation and minimise the risk of capture, but on the other hand, this attempt was undermined by ideas from the culture of 'club' government, in which decisions were taken by a small group of key individuals with no formal external accountability. Club government was in crisis by the 1970s and being dismantled in the 1980s, but its norms and values were still sufficiently entrenched in government to help form the design of regulatory institutions. In particular, and by contrast with the American system with its principles of public accountability and the influence of legally-backed direction of regulators,[93] the newly created British system (first seen in the telecomms regulator Oftel and subsequently copied in energy) involved an individual Director General rather than a regulatory board, and a broad framework of powers in a 'light touch' legal framework (Moran 2003: 105-06).

This arrangement has proved persistent. As DECC's 2011 review of Ofgem noted, successive changes to the regulator's remit and duties have "not succeeded in consistently and transparently achieving the desired coherence between the overarching strategy and the regulatory regime. This disconnect can be attributed to two characteristics of the existing legal framework: the broad scope of the duties and the weak legal status of the Guidance." (DECC 2011a: 24). The review goes on to acknowledge that the specification of Ofgem's duties has been "intentionally broad to allow the regulator flexibility".

A number of consequences flow from the relatively high degree of autonomy of Ofgem. One is a degree of 'regulatory inertia' (Faure-Grimaud and Martimort 2003), i.e. when the government has wished to adopt new policies, Ofgem has tended to lag behind in reflecting these new priorities in regulation. As described in section 7.3 above, the objectives of cost efficiency and an intellectual framework of regulatory economics have been heavily entrenched in Ofgem for 30 years, and this has meant that attempts have been made to fit new objectives into existing frameworks and to tackle those objectives with existing tools. In some cases, government has become frustrated with the regulator and stepped in directly (on renewable energy, examples include Connect and Manage and the OFTO regime).

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[93] New York provides a current example where the state government has given far clearer and more specific direction in the changes it wants to see in networks and retails markets, directing the Public Utility Commission 'to enable and facilitate new energy business models for utilities and ESCOs' and to maximising the cost effective utilisation of DER (NYS 2014: 1).

However, it is not the case that Ofgem has been completely impervious to changes of direction in government policy, and the review of RPI-X, the creation of the LCNF, the shift to RIIO, and the establishment of the Sustainable Development Division can also be seen in this light. Institutional change is a complex process, typically involving both external influence and actors working from within, and a series of what appear to be incremental changes can still have quite dramatic effects, especially over a longer period of time (Mahoney and Thelen 2010). The evidence on change in network governance presented above implies that, over the last 15 years, change at the level of discourse, new institutions and some aspects of the regulatory framework have been quite substantial, but change in network investment and practice still remains slow.

A second consequence is that, as noted by the Energy Networks Association at the time of DECC's review (ENA 2010: 2), Ofgem is left to interpret policy, including trade-offs between policy objectives, in the way it chooses. Policy trade-offs are inherently political in their nature. If such trade-offs (for example between short-term costs and decarbonisation) had been decisively resolved by government, then Ofgem's task would be more straightforward (and its room for manoeuvre correspondingly less). But in fact government has not resolved wider societal disagreements about energy policy trade-offs. This can be seen, for example, in the difficulties encountered in the implementation of the Climate Change Act especially since 2010 (Lockwood 2013). As a result, Ofgem is constantly having to make decisions that are inherently political.

An example in network policy is the treatment of risk and trade-offs with cost. In the move to smarter grids, Ofgem has created a mechanism for R&D, at a significant cost to consumers. That mechanism is beginning to produce potentially scalable network solutions, but transferring these to BAU investment or practice still involves some risks for companies, and Ofgem has to make decisions about where to place the balance between companies and consumers bearing that risk. To an extent, Ofgem has been making such judgements for many years, but in circumstances where technology was relatively stable and risks relatively well known. Trade-offs are more difficult and more political where there is more uncertainty.

The inherently political trade-off between cost and security of supply has also been delegated. As discussed in detail above, technical standards in particular imply a particular set of values in the trade-off between network costs and security of supply, or network reliability, i.e. underlying, sometimes implicit assumptions about the value of lost load (VOLL) and desired loss-of-load probability (LOLP). These assumptions, which originated some 50 years ago, in turn reflect not so much an optimisation of this trade-off, as concerns about effects on commercial reputation (for companies) and electoral damage (for politicians) of the lights going out. During periods of stability in the socio-technical system, such an approach may be appropriate (although there can still be debates about whether there is excessive gold-plating, the costs of which have to be borne by consumers). However, in a transition, in which the value of greater optimisation of the security-cost trade-off increases sharply and the ability to manage that optimisation through ICTs improves, there are strong arguments for reviewing the approach, and opening up the nature of the trade-off to wider societal debate.

These issues are not new – Owen (2004) discusses the tensions between the function of economic regulation and the achievement of social and environmental objectives in both energy and water, and called for the introduction of a sustainable development duty for Ofgem. This in fact followed in the 2004 and 2008 Energy Acts, but it has not resolved the underlying problems.

7.4.2 The relationship between Ofgem and network companies

Transition in networks (and more widely across the energy system) inherently involves greater uncertainty, about technologies, costs, markets and institutions. One response to the problem of uncertainty is to allow evolution and avoid costly mistakes by allowing experiment and deeper engagement with network users to understand potential future uses (e.g. Pollitt and Bialek 2008). This approach fits well with a delegated approach to governance. The other is to move in the opposite direction towards a greater degree of strategic coordination, or a 'system architect' as many have called for (Smart Grid GB/Ernst and Young 2010, ENA 2009b, Skillings 2010, IET 2009, 2013, Sansom 2010). The Smart Grid Forum itself notes 'there is continuing need to provide strategic direction on the future of the electricity system and smart grids to build and sustain confidence in the direction Great Britain is taking. Without this it is difficult for the industry, consumers and the supply chain to invest for the future' (SGF 2014a: 31).

This latter theme arises at different levels. At the level of smart grid design, there is uncertainty about what kinds of technologies and associated practices will be developed and become dominant. There is also the need to ensure that all the different elements in a smart electricity system, including distributed generation (some which is variable renewables), smart meters and automated home systems, controllable electric vehicles charging and heat pumps, data handling systems, network sensing, active network management and automated intelligent network devices, are all compatible with each other. In the absence of technical standards and some form of shared approaches to system architecture, there are risks of lack of interoperability and stranded assets (Shaw et al 2012: 5932).

At the level of demand and generation on distribution networks, there is uncertainty about the future growth and location of distributed generation and low carbon technologies such as heat pumps and electric vehicles. If investments in network capacity are made to meet this growth in a piecemeal unplanned way then potential cost savings may be missed. On the other hand, if network plans are made that are not consistent with actual demand and generation growth, then assets may be stranded.

There may be similar opportunities and risks to coordination in the *scaling up of supply chains* (Deasley et al 2104: 29). The RIIO ED1 business plan from Electricity North West notes the contrast between the UK, where determination of the pace of change is delegated to DNOs, and the US and Europe, where a more coordinated and/or directed approach is building a smart grid supply chain more quickly:

> *‘We conducted a number of reference client engagements with both British DNOs and with US electricity and gas companies. We found that internationally, the maturity of the smart grid roadmap and integration to Advanced Meter Infrastructure (AMI) is generally more advanced than in the UK. As a consequence most of the real time systems vendors with implementations across Europe and the US have already started to move their core systems along the smart future roadmap and some have mature offerings in demand side management, contract management and advanced meter infrastructure.’ (ENW 2014: 96)*

At the level of the *wider electricity system* there are coordination problems arising from the fact that some of the benefits of the smart grid will fall to actors who are different from those who have to make investments (see section 4.6 above and Bolton and Foxon 2010: 20). The ability of network operators to realise the benefit of smart grid investments will be dependent on investments by others (for example, suppliers investing in smart meters). It may not be possible for network companies to pass on the costs of developing that capability or to capture an appropriate share of the benefits, meaning that the incentive to innovate is weakened (e.g., Bolton and Foxon 2010: 20, Ward et al 2012a). This ‘broken’ or disaggregated value chain issue (Bialek and Taylor 2010) arises across a number of aspects of regulation and policy, and is accentuated in the UK because of the particularly thorough nature of privatisation and unbundling in the electricity industry (Cary 2010: 67).[94]

[94] Ironically, although this situation potentially implies a greater role for government, the privatisation process itself has hollowed out the technical expertise that would be needed (e.g. IET 2009) – see also below

The RPI-X@20 review explicitly engaged with the question of how far a ‘guiding mind’ was needed to direct the shape and role of future networks, and how far decisions should be delegated (Ofgem 2009f). The review laid out three options: a ‘central government led’ model in which government maps out a plan of how energy networks would facilitate delivery; a ‘joint industry led’ model in which distribution and transmission network companies makes proposals for such a map that is then endorsed or amended by government and Ofgem; and an ‘adapted regulatory framework’ in which networks are given outcomes that they are then incentivised to deliver. Unlike the other two models, the adapted regulatory approach was not centralised, but rather left decisions on what network companies would need to do with those companies within the regulatory framework set up by Ofgem, taking into account higher level Government and EU targets (Ofgem 2009b: 12).

While a central government led model was acknowledged to potentially speed up change in networks, it was rejected on the grounds that it might be excessively costly and not allow enough innovation, and might take too short term and political a view. The joint industry led model was also rejected as risking insufficient innovation and not prioritising efficiency. Ofgem (2009b: 15) argued that the adapted regulatory model ‘is potentially the most likely to ensure value for money for existing and future consumers over time’. The main reason put forward for preferring this approach was that, because of the considerable uncertainty about what the efficient option for a smart grid is, any centralised approach risks imposing risks that are far more expensive than they need to be, relative to a more evolutionary and incremental approach.

In some areas, Ofgem has followed this delegated model for its relationship with network (and other) companies. As section 7.2 describes, governance of industry codes has largely been delegated to industry actors themselves for many years. Ofgem has also delegated large parts of the innovation and smart grid development agenda. As described in section 3.1.6 above, the development of scenarios for low-carbon technology development has been left to DNOs. The LCNF is run on a competitive bidding system basis, in contrast with cases such as Denmark, where R&D has been more centrally coordinated (Lehtonen and Nye 2009: 2343). Companies are being invited to develop their own smart grid strategies.

If a regulator has a clear idea of the outcomes it wishes to see, and if the companies have strong incentives to produce these outcomes, then the delegated model may well succeed. However, it is not clear that this is yet the case with innovation for smarter grids and the demand side. First, as discussed above in sections 3.1 and 4.1, it is not yet clear whether incentives for network companies are strong and aligned. Second, specifying outcomes for a smart grid or for a network that supports a demand-side oriented system may be difficult.

Since 2005, Ofgem has increasingly tried to specific the regulatory contract more completely by giving incentives for network companies to produce a set of outputs relating to network performance and functioning. These changes are beginning to shift the basis of network regulation from simply providing capacity at least cost to providing *capability*, i.e. separating out what networks can do from simply how big or efficient they are.[95] Capacity may still be one route to providing network capabilities, but it will not be the only route. As Ruester et al (2014: 4) put it: 'The focus of regulation has to shift from achieving operating efficiency gains towards facilitating the achievement of environmental and supply security objectives'

However, outputs so far largely relate to safety, reliability and customer satisfaction rather than facilitating decarbonisation and demand side flexibility. Given that the technologies, final architecture and capabilities of a smarter grid are still uncertain, the question is whether a regulator can specify a regulatory contract for the delivery of a smart grid or the demand side in a well-defined and effective way.[96] New York State, which is also seeking a move towards a 'distribution service platform provider' model, notes that: 'Developing specific metrics will undoubtedly be a challenge. Setting specific metrics for new performance areas where there is no track record (e.g., DER-related outcomes) will require careful deliberation' (NYS 2014: 52).

In keeping with the emphasis on delegation, Ofgem's approach appears to be to try to specify outputs as near as possible to final outcome, i.e. requiring DNOs to be able to facilitate their own forecasts of distributed generation and low-carbon technologies on their networks efficiently. To try to avoid a simple expansion of capacity to meet these challenges, it also requires companies to have a smart grid strategy. An alternative more directive approach is would be to specify a number of more intermediate outputs. For example, Ruester et al (2014)

[95] This distinction is analogous to one that can be made in electricity capacity markets, i.e. between markets that reward capacity in general and those that reward particular types of capabilities, e.g. fast response times, reliability (e.g. Keay-Bright 2013)

[96] Or even be certain which actors it should be regulating - Agrell et al (2013) argue that regulation which treats networks and actors offering distributed energy resources (e.g. DG, DSR etc.) together as teams would produce superior outcomes to situations where networks are regulated and contract separately for DER services, mainly because of informational asymmetries. The experience of another episode of rapid technological change in a regulated utility area, i.e. telecoms, may be limited, since in that case parallel networks emerged providing open competition, whereas it is not clear that this will be viable in electricity.

point to work by CEER (2014) in specifying 9 such outputs.[97] It is as yet unclear which approach (or combination of approaches) will be the most effective.

While Ofgem's official position, following the RPI-X@20 guiding mind review, appears to favour delegation within a regulatory framework wherever possible, in practice, there are a number of areas where Ofgem (sometimes together with DECC) is actually taking a more active coordinating role (sometimes after the failure of markets or standard regulatory approaches to yield results):

- The Smart Grid Forum, set up jointly with DECC, and bringing together DNOs with other industry actors, plus the ICT industry. Amongst other things, the SGF is giving guidance on the growth of LCTs, producing a set of functionalities for smart grids to guide DNO plans, discussing smart grid architecture, assessing regulatory barriers etc. Industry itself seems to regards SGF as having a key coordinating role (see Ofgem 2013: 12)[98]
- The Distributed Generation Forum, bringing together DNOs with DG investors and associations, to facilitate better understanding especially of problems faced by the latter group, and improving information flows
- Coordination of offshore transmission line planning,[99] (following criticism by the National Audit Office 2012)
- A Flexibility and Capacity Working Group convened under the auspices of RIIO-ED1 to identify remaining issues that may act as barriers to the development of demand side solutions (Ofgem 2012f).
- The design and roll-out of smart meters, which government and Ofgem originally hoped would be led by suppliers.
- The Integrated Transmission Planning Regulation group, working on more integrated planning of on-shore and off-shore transmission together with interconnection (Ofgem 2012e).
- A Demand Side Response framework group (see above section 4.6.2)

[97] These are: Hosting capacity for distributed energy resources in distribution grids; Allowable maximum injection of power without congestion risks in transmission networks; Energy not withdrawn from renewable sources due to congestion and/or security risks; Measured satisfaction of grid users for the "grid" services they receive; Level of losses in transmission and distribution networks; Actual availability of network capacity (e.g. DER hosting capacity) with respect to its standard value; Ratio between interconnection capacity of one country/region and its electricity demand; Exploitation of interconnection capacity (particularly related to maximization of capacity according to the Regulation on electricity cross-border exchanges and the congestion management guidelines); and Time for licensing/authorisation of a new electricity transmission infrastructure.

[98] There are also a number of other initiatives underway by different actors, including work on data by the Energy Networks Association, Technology Strategy Board research on whole system engineering along with an IET expert group looking at complexity, and a smart grids skills strategy by the National Skills Academy for Power.

[99] https://www.ofgem.gov.uk/electricity/transmission-networks/offshore-transmission/offshore-transmission-policy-design/coordination-policy

There are two potential issues with this pattern. One is that Ofgem is in danger of operating an un-strategic mix of delegation and coordination that evolves in an *ad hoc* manner. It is not always clear why Ofgem denies the need for coordination in one area but justifies it in another. For example, on the need for coordination in the formation of a DSR framework, Ofgem argues that, despite the activity of other groups working in the area, 'Given that we set many of the rules that will impact the future development of demand-side response, Ofgem necessarily has a role in examining how well the regulatory framework enables commercial arrangements that provide for the efficient use of demand-side response, across the supply-chain' (2013e: 5) and that "Ofgem best placed to take an industry-wide perspective with a view to developing rules that maximise system-wide value (as opposed to industry parties who are likely to have differing priorities)" (ibid: 14-15). However, as the same arguments apply to distributed generation, for example, it is not clear why Ofgem has not been more active in coordinating different industry actors in a framework for DG that encompasses DNOs, TOs, suppliers and DG owners.

A second issue is that effective coordination requires good information and sometimes technical knowledge. In other countries such as Germany and Denmark, where governments, ISOs and regulators do more less delegation and more coordination, both information and technical capacity available to the public sphere is greater than in the UK, where these both went to the private sector long ago. In such circumstances the two risks are, firstly that coordination by regulator or government is poor,[100] and secondly that coordination itself is delegated to the private sector. Indeed, Ofgem and the government appear to have become increasingly dependent on National Grid to play a coordinating role in a number of areas, including transmission/interconnection, CfDs, capacity mechanism etc., precisely for this reason.

[100] Some argue that this is the case for smart meters, for example.

8. Conclusions

This paper has examined the current rules and incentives that govern energy networks in Great Britain from the perspective of how far they work for or against the development of 'distributed energy resources', i.e. distributed generation, demand-side response, small-scale storage and energy efficiency, with a special focus on the first two of these.

In *electricity distribution networks* (section 3) there has been considerable change over the last decade at the level of regulation and discourse, especially in relation to 'smart grids'. Spending on R&D and demonstration projects has increased from the region of £2m a year to around £100m a year, and there is some evidence (albeit uneven) of a change in culture and capacity for innovation within DNOs. There has also been an upswing in the amount of generation capacity connected to distribution networks in the last few years.

However, at the level of network planning and operation in practice, change is still marginal. In theory, while barriers relating to capital expenditure bias have been removed, network operators still have a basic interest in network growth. Looking ahead as far as 2023, anticipated savings from smart grid approaches and technologies in practice remain very small, partly because of expectations that the growth of electric vehicle charging and heat pumps use will be slow before 2020.

In terms of cost signalling via charges, existing distribution charging methodologies for electricity demand give quite strong signals on long-term peak network costs for half-hourly (HH) metered customers. Non-HH metered customers currently receive no signals of the value of demand reduction or response, although this should change with smart meter roll-out. For households and small businesses, real-time distribution charging is likely to have to be of a critical peak nature, or involve automated response, to become material. All these changes will involve modifications of code containing the charging methodology. In addition, there are a number of other reasons why charging to drive demand away from peak periods to reduce network costs may be difficult, including the fact that DNOs have no direct relationships with customers and the likelihood that in most cases the value of DSR will be greater to integrated supplier/generator companies, whose interests may at time conflict with those of network companies.

Finally, the engineering regulations required for security of supply used in the planning of distribution networks do not currently recognise controllable demand (i.e. DSR) and may need changes in other areas to allow use of dynamic line ratings, storage and automated or remote network reconfiguration. A review of these regulations is currently on-going.

In *electricity transmission networks* high constraint costs are driving network expansion rather than demand-side solutions to network congestion problems. As with distribution networks charging, transmission charging gives time-of-use signals to HH-metered consumers but not the mass of non-HH-metered households and SMEs. While the latter group may receive such signals in future, this would require modifications to the code governing charging. Materiality for this latter group will also be an issue, since transmission costs are small portion of total bills. For large consumers, whose charges are based on Triad consumption, signals are quite strong, and Triad avoidance appears to be increasing. But this charging arrangement, driven by cost-reflexivity rather than a DSR objective, falls short of full dynamic charging.

Transmission planning remains basically supply focused, with Transmission Entry Capacity concept privileging generation over demand response or reduction. Planning standards for transmission networks have also been criticised for gold-plating and inflating network costs. This debate comes down to trade-off between cost and security of supply, and therefore views on the value of lost load.

Demand response does play a small role in system balancing, via ancillary services, and this is set to increase with new reserve instrument. However, the total market for industrial and commercial demand side remains small in relation to other cases, such as PJM in the USA, and technical requirements may be a barrier.

Exports from distributed generation (DG) onto transmission networks growing and becoming significant, showing how transmission capacity is both a complement for DER and at the same time is displacing centralised generation. National Grid is seeking to start charging DG more for the use of transmission capacity, but at present has shelved these plans. There is an absence of an overall plan for these interactions that is independent of the interests of TOs.

By contrast, Ofgem is taking an active and direct role in coordinating the development of a framework for demand-side response DSR, as it has become clearer that DSR relationships between one actor and a consumer could have spillover effects on other actors.

Overall, the relationships between DER, transmission capacity and centralised generating capacity are complex. Distributed energy resources, including demand side response, are both a complement to and substitute for transmission and interconnection capacity. However, thinking on the interaction between system operation at the national level with DSOs remains at very early stage. There are calls for a ‘system architect’ to coordinate what is likely to be increasing complexity, but Ofgem’s position has been that a ‘guiding mind’ is not needed.

In *gas networks*, the long-term issue is how far these will become redundant if heat is electrified and no alternative use can be made of the networks. In the near term, gas distribution and transmission network operators appear to be moving away from the use of demand side contracts to manage network congestion, although this may reflect the recent fall in peak demand because of the economic depression. In the absence of supportive policy and regulation *heat networks* in Britain remain marginal and underdeveloped, especially when compared with other countries in Europe.

Most of the key rules and incentives in energy networks derive from two frameworks: economic regulation, and industry codes and standards together with the associated licences. Economic regulation has been governed by Ofgem (and its predecessors), and has had an historic remit of cost reduction and economic efficiency, to which has been added a sustainable development remit. The relationship between government and Ofgem is characterised by a high degree of discretion, leaving many trade-offs in the hands of the regulator, despite their political nature. There is currently no explicit government plan for smart grids. The regulator interprets innovation for sustainability within a framework of long-term efficiency, and in seeking to minimise the risk of stranded assets being placed on consumers, has delegated network innovation to network companies. A substantial part of the governance of codes and standards lies in the hands of the energy industry, and particularly the large incumbent and monopoly firms that have the resources to participate in the modification system.

The British system of energy governance has been dominated by principles of economic liberalisation and delegation since the 1980s. These arrangements are intended to increase the credibility of policy and reduce costs. However, they have also delegated essentially political decisions to actors who are not necessarily best placed to resolve them. As a result, government and the regulator have increasingly intervened both in markets and in processes relating to networks, although such intervention appears ad hoc rather than strategic, and it is not clear that state actors always have the capacity and information to intervene to greatest effect.

Annex 1: Interviews

1. Phil Jones, CEO, Northern PowerGrid – 5 July 2013

2. Judith Ward, Director, Sustainability First – 10 July 2013

3. James Harbridge, Energy and Environment Programme Manager, Intellect – 30 July 2013

4. Rob McNamara, Executive Director, SmartGridGB – 30 July 2013

5. Iain Morgan, Senior Regulatory Economist, Network Regulation Policy, Ofgem – 14 November 2013

6. Phil Baker, Freelance Consultant and BSC Panel Member– 14 November 2013

7. Richard Lowes, ex. Scotia Gas Networks – 10 February 2014

8. Lewis Dale, National Grid – 24 February 2014

9. Dave Openshaw, UKPN and Smart Grid Forum member – 27 February 2014

10. Mike Kay, Networks Strategy and Technical Support Director, Electricity North West – 28 February 2014

11. Chris Welby, Policy and Regulatory Affairs Director, Good Energy – 11 March 2014

12. Tim Tutton, Independent Consultant – 22 April 2014

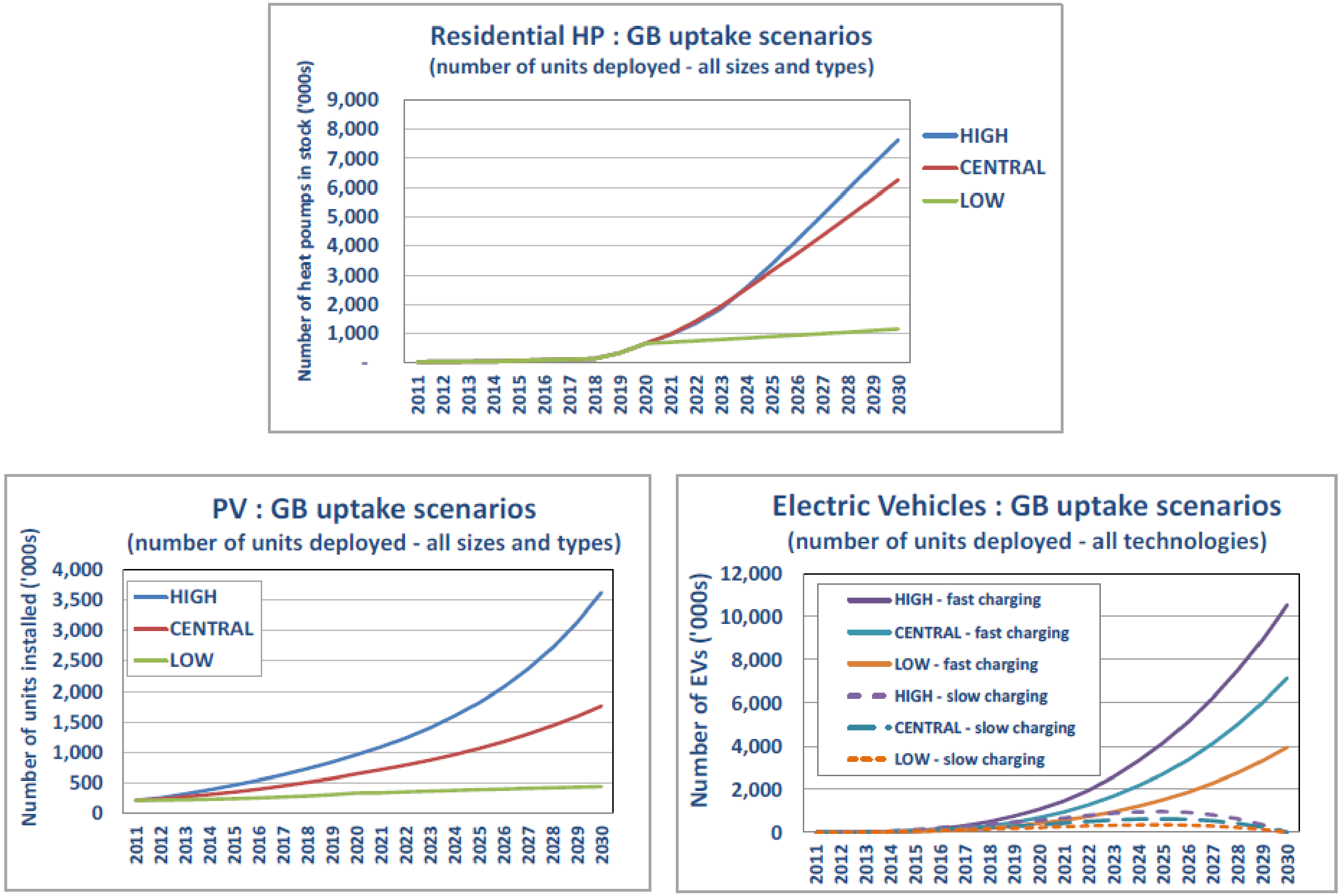
13. Simon Roberts, Centre for Sustainable Energy and Ofgem Consumer Challenge group – 5 August 2014

Annex 2: Uncertainty about the growth of low carbon technologies

Table A.1: DNO 'best views' on LCT growth in RIIO-ED1 Business Plans

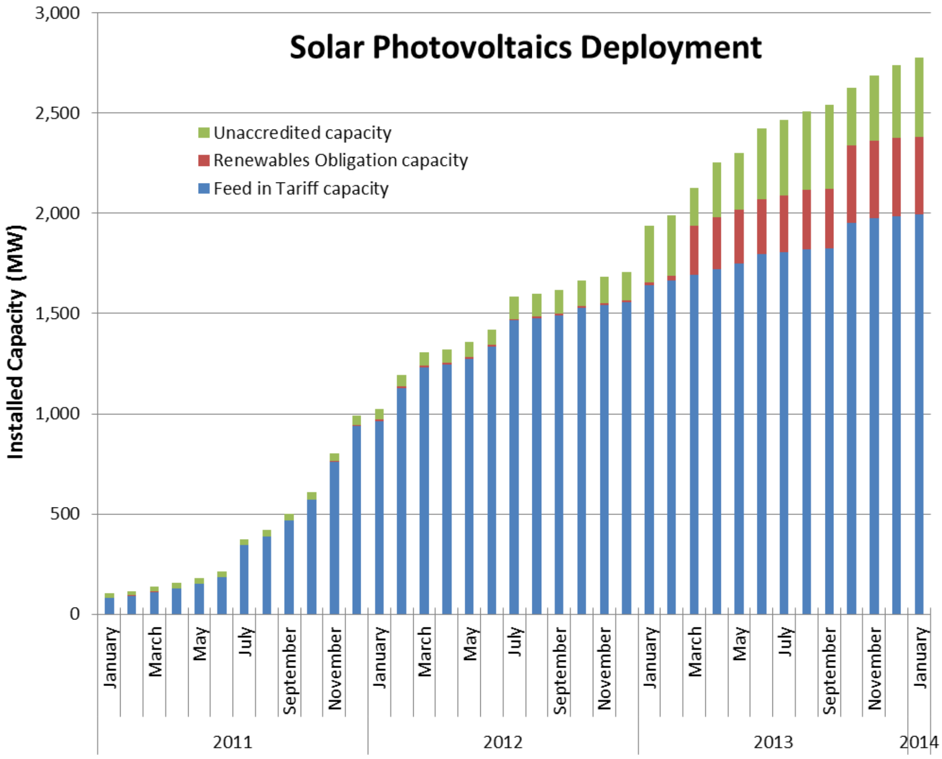
Company	Business Plan Document	Best view
Electricity North West Limited	Annex 8: DECC Scenarios	"LCT take up will be lower in the North West than the national average. As such we have concluded that the DECC Low scenario is the most probable estimate for RIIO-ED1 for our region." (p. 4)
Northern Power Grid	Annex 1.9 Smart Grid Development plan	"while…we are unlikely to reach the volumes of PV in DECC's high forecast, for PV the assumption of 'medium' is an entirely appropriate one…" (p. 10). In contrast they think HPs and EVs will grow more slowly, with HPs taking off before EVs
Western Power Distribution	Supplementary Annex SA-06 - Uncertainty	Best view estimates are well below DECCs scenarios other than 4 (i.e. buying international credits). WPD thinks the DECC scenarios will not materialise in their regions (p. 8). On the other hand, WPD think there will be a higher degree of clustering of LCTs than in the Transform model, which raises costs (see p 9).
	Minutes of meeting of the WPD Customer Panel meeting on 13 March 2013	A Director (?Nigel Turvey?) of the company is recorded as telling the meeting that WPD viewed the DECC scenarios as "very ambitious".
SP Energy Networks	Main Business Plan	'Best view' of LCT roll out falls between DECC's low and medium scenarios (p. 194)
SSE Power Distribution	Technical Appendix 04: Getting connected to our network	"Our decision is based on a low LCT take-up (most closely aligned to DECC scenario 4)" (p. 34)
UK Power Networks	Annex 3: Core Planning Scenario	"The graph generally demonstrates that our current baseline uptake rates are towards the lower end of the DECC/Smartgrid Forum forecasts over the long term." (p. 12)

Figure A.1: GB uptake scenarios for different LCTs



Source: EA Technologies 2012: 22

Figure A2: Growth in UK installed solar PV capacity 2011-14



Source: DECC (2014) *Energy Trends* Table ET 6.4

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