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Developing networks for the low carbon energy future

Working Paper

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KEITH BELL, UNIVERSITY OF STRATHCLYDE
GRAEME HAWKER, UNIVERSITY OF STRATHCLYDE

This working Paper has been prompted by an inquiry into 'low carbon networks' launched in September 2015 by the House of Commons Select Committee on Energy and Climate Change. A response on behalf of UKERC has been submitted to the Committee. This present paper expands on many of the themes included in that response and provides more detail and discussion.

+44 (0)141 548 4651 keith.bell@strath.ac.uk

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1 Introduction

This UKERC working paper has been prompted by an inquiry into 'low carbon networks' launched in September 2015 by the House of Commons Select Committee on Energy and Climate Change[1]. A response on behalf of UKERC has been submitted to the Committee. The present paper expands on many of themes included in that response and provides more detail and discussion.

An existing electricity system's infrastructure is designed to meet consumers' demand for power when that demand occurs. The annual peak demand for power is fundamental in dimensioning the total generation capacity that converts energy from different sources into power. Different fuels are available in different places. Although many of the fuels can be moved, they are moved at a cost that should be compared with that of transferring the energy once it has been converted into electricity. Hydro, wind and solar power can most cost-effectively be utilised in particular places. These factors lead to the construction of power networks to transfer power from generators to the electrical loads that consumers use to fulfil particular energy service needs.

The demand for power varies in time – for example, it tends to be highest during the day or, in winter, early evening – and in space. However, the power available from generators also varies not only because the wind does not always blow or the sun shine. Generating units, including very large ones, can suffer faults and need to be taken offline from time to time for maintenance. These variations mean that the available generation and demand are not always balanced. The system can be rebalanced by making use of storage, which does not mean solely by means that can convert both to and from electricity. For example, gas, coal or water can be stored and, given enough notice to start up the generating plant, used to generate electricity when required. Alternatively, in principle, the timing of demand for electricity can be changed so it matches the moments at which generation is available. (This already happens, though not yet to any great extent). Alternatively, imbalances can be matched in space. That is, given enough network capacity connecting two areas, a surplus of available power relative to demand in one area can be shared with another that has a deficit, and vice versa. This allows a sharing of reserve generation capacity between different areas, reducing the total reserve required and supporting security of supply, and was the original motivation for the development of the national grid in Britain in the 1930s to 1960s. However, since the 1960s it has been recognised as also facilitating the use of

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[1] See http://www.parliament.uk/business/committees/committees-a-z/commons-select/energy-and-climate-change-committee/inquiries/

the cheapest generation resources, something that would now be described as facilitating competition in the electricity market.

In respect of the renewable resources that, in recent years, have been developed most rapidly in Britain – wind and solar – the primary energy source cannot be stored. However, it is also the case that storage of the energy released through nuclear fission is difficult or costly (this is what the original pumped storage stations were mostly motivated by), and frequent upward or downward regulation of the rate of fission must be carefully controlled and built, at a cost, into the design of nuclear power stations. Although we are yet to see it in Britain, power stations designed to burn fossil fuels and capture and store the CO_2 emitted might also adjust their output but must be designed to do so, again at a cost.

This paper discusses various issues associated with the development and operation of networks to facilitate and transfer energy derived from low carbon sources such as renewables, nuclear power and burning of fossil fuels with carbon capture and storage. It starts by briefly describing the limitations of present day networks before moving on to discuss the likely features of a network for low carbon energy and how it should be developed and operated, the facilitation of new connections to the network, the roles of the network licensees, the key technologies and the support of innovation and, before drawing some overall conclusions, some lessons that can be learned from other countries.

2 What are the limitations of today's electricity infrastructure and how can these limitations be addressed?

The power system that we have in Britain at present has been largely successful at meeting electricity needs at reasonable cost and reliability for many decades, but it has finite capacity. It is now being challenged in a number of ways, some of them due to closure, for various reasons, of established generation capacity. In addition:

1. the type of generation that has grown most in recent years and is expected to continue to grow significantly is intermittent renewables, in particular wind and solar PV, which have the following characteristics:
    a. many of the new generators are being connected at locations that have least network capacity, e.g. on the geographical periphery of the existing system such as in remote onshore locations or offshore, or on the electrical periphery, i.e. within the lowest voltage parts of the distribution network;

    b. output of wind and solar PV is highly variable and somewhat uncertain which presents challenges for system balancing;
    c. operation of wind and solar power leads to a reduction in system inertia and, as a consequence, different system dynamic performance;
2. many network as well as generation assets are reaching or have gone beyond their expected lives and, depending on future development of demand and generation, will need to be replaced;
3. to meet overall energy decarbonisation targets there might be significant electrification of heat and transport and associated large increases in demand for electricity and flows on the network.

Although the power system and network challenges associated with wind and solar power have been quite widely discussed, developments of new nuclear power stations present their own difficulties. For example, it is our understanding that the connections of Hinkley Point C and NuGen's proposed Moorside station would both require significant transmission reinforcements. In addition, without new nuclear stations having an ability to flex their output, their operation alongside intermittent renewables would entail periods when renewables' output may need to be curtailed. Finally, a system heavily dependent on nuclear power and intermittent renewables would make a 'black start' of the system after a major unreliability event very challenging.

One particular issue associated with the connection of solar PV, most (if not all) of which is expected to be to the distribution networks, is that, at present, distribution is neither comprehensively monitored nor actively controlled.

Possible means by which these limitations might be addressed are discussed in the next section. While these include network reinforcement at local, national and European scales, the level of reinforcement can be reduced by smarter system operation.

3 What will a low carbon network look like, what are the challenges in achieving it, and what benefits will it bring?

The nature of a 'low carbon network'

A 'low carbon network' can be understood to be a network that permits the transfer of energy derived from low carbon sources to locations where it is used. There can actually be multiple low carbon networks, e.g. transferring water heated by energy from low carbon sources, or gases manufactured using low carbon energy, e.g. hydrogen or synthetic methane, and technologies such as micro combined heat and power promise efficiency benefits without totally eliminating carbon emissions. However, in this paper we will concentrate on electricity networks that form part of a low carbon electric power system. This is because, at present, this is the network that transfers most low carbon energy, and is the form of energy that is arguably the most flexible in respect of its use and options for production and, notwithstanding the attractions of, for example, a 'hydrogen economy', it appears to offer the best prospects of meeting the main goals for a low carbon energy system that can be realised in the next 10–20 years: affordable, reliable and safe. However, as time goes on, not least as Britain's demand for heat becomes progressively decarbonised, these other networks should not be neglected as they have a potentially very important part to play within a low carbon energy system. It should be ensured that all elements work successfully in concert with each other so that all aspects of energy need are met.

The cost of decarbonising electricity while still providing an acceptable reliability of supply could be very high so a key measure of the success of a future low carbon power system will be that it minimises the cost of additional infrastructure. This can be achieved by maximising the utilisation of whatever infrastructure exists. This would also have the benefit of minimising the perceived intrusiveness of the power network, e.g. through reducing the need for additional overhead lines.

'Corrective' and 'preventive' actions

Although 'corrective actions' of one form or another have been a feature of power systems for many decades, it may be argued to increase the average utilisation of assets we need to make more extensive use of such actions and of flexibility of demand. The alternative to corrective actions – 'preventive actions' – recognises, on timescales from around a minute-ahead up to around a day-ahead, uncertainties associated with the level of demand and availability of generation and the possibility of unplanned and unavoidable changes such as a fault outage of a network branch or a generator. Often, the preventive action is to restrict outputs from certain generators or flows on the network simply to provide some margin for response to changes. This inevitably leaves some system capacity under-utilised. However, many of the changes might be manageable through good forecasting or else, often, simply do not occur.

Instead of preventive actions, average network and low carbon generation utilisation can be increased by (a) being more precise about what the operating limits really are instead of using limits defined based on conservative assumptions; and (b) identifying actions that can be taken after a disturbance without restricting initial output from the cheapest generators[2].

[2] In respect of short-run marginal costs, low carbon generators are the cheapest.

Improved network monitoring

The passage of current through electrical conductors causes them to heat up. One of the key operating limits of a power system is that conductors do not become too hot. Historically, thermal ratings have been assigned to each branch of the network to ensure that conductor or insulator temperatures are not excessive and system operators will limit the power flow if necessary, mainly through changes to the generation dispatch. However, real-time monitoring or, based on measured ambient conditions, estimation of actual conductor temperatures can allow more current to pass than conservatively set 'static' ratings would suggest, and so increase the utilisation of existing assets. Power transfers are also limited by system stability issues. New devices such as phasor measurement units (PMUs) promise to allow these limits to be calculated more precisely and so progressively reduce the size of 'safety margins'.

More extensive use of corrective actions and the 'smart grid'

Actions taken after a disturbance include automatically curtailing the output of generators operating in export-limited locations and quickly making use of reserve power elsewhere (provided it is available); or, where possible, reconfiguring the network to make use of whatever margin is available under the present condition. Given that the relevant technology is already installed on the system, the latter can be achieved by, for example, 'phase shifting transformers', thyristor controlled series compensation or embedded high voltage direct current (HVDC) connections such as the West Coast Link currently under construction between the South of Scotland and North-East Wales. HVDC makes use of power electronics and seems to offer particular attractions as it provides the potential for implementation of new 'supplemental' controls that, if correctly designed, can contribute to management of dynamic responses of the system. Power electronics are also integral to solar PV and many wind turbines and, again, offer some degree of flexibility if appropriately designed. Their potential is also now being explored for use on the distribution networks. However, the relatively high resistance of the lowest voltage branches of distribution networks limit the effectiveness of various innovations at particular locations.

It should be emphasised that the power system in Britain already makes extensive use of corrective actions, e.g. for management of system frequency or for ensuring that exports of power from Scotland to England remain stable. However, while the majority of reserve power in the past has taken the form of part-loaded or standby generation and contributes to meeting imbalances arising from higher than expected demand or lower than expected availability of generation, there is increasing recognition of the potential for flexible demand to contribute. That is, some users of electrical energy might be prepared to reduce their demand by delaying the service they gain from it to another time. For users that have some flexibility, they could be encouraged to use it by being offered recompense for adjustments or lower tariffs. Thus, particular consumers can especially benefit, but all consumers should benefit from lower total system costs. Such measures can be particularly effective when properly planned. For example, good forecasts of available renewable power can be used to inform users when would be the best time to use electricity or when a response margin should be made available and is most likely to be used. The potential for demand to be flexible depends on the use different actors make of electricity and their access to storage. For example, hot water tanks or well insulated buildings provide thermal storage that is much cheaper than an equivalent energy capacity provided by a battery.

The more extensive use of corrective actions is arguably the essence of a 'smarter grid'. However, one word of caution should perhaps be introduced: there is always the possibility of a control action being delayed or not taking place at all. Although corrective actions promise to reduce average system operation costs and deliver, in the long term, similar reliability of supply to that which we experience now, the more reliance is placed on them, particularly on time critical actions, the more vulnerable the system might be expected to become to occasional quite large interruptions to supply. Although some technologists like to talk about a 'smart grid' being smart through use of 'intelligent' devices, actually the critical thing that needs to be 'smart' is the designer of the system and its component parts. This, in turn, places an emphasis on the recruitment and training of talented engineers into the power sector that, in our view, is insufficiently widely recognised[3].

Significant network reinforcement almost certainly required

As a final and, we believe, very important observation on what a 'low carbon network' might look like, we note that, whatever the benefits of a 'smarter' grid, progressive decarbonisation of the electricity system will, without doubt, still require significant investment in 'primary' assets, i.e. those that generate, transmit or distribute power. At the very least, they will be needed to connect new low carbon sources of power to the transmission system. Although 'smarter' operation ought to reduce the extent of need for deeper reinforcements, we are aware of no transmission studies at a GB or European scale that credibly suggest they can be avoided in the next 10-20 years and beyond. Indeed, the European Ten Year Network Development Plan suggests a requirement for major investment in that timeframe[4]; beyond that, various studies, albeit conducted at a very high level and inevitably dependent on a range of assumptions, suggest a need for

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[3] For further discussion, see, for example, Keith Bell, "Methods and Tools for Planning the Future Power System: Issues and Priorities", August 2014, available http://www.theiet.org/sectors/energy/resources/modelling-reports/papers.cfm

[4] The Ten Year Network Development Plan (TYNDP) is produced through the European Network of Transmission System Operators for Electricity (ENTSO-E) every two years. The most recent edition can be found here: https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2014/Pages/default.aspx

massive further investment[5]. These developments will present major delivery challenges in respect of planning permissions, supply chain and skills; if they are not delivered, they will present a major threat to deep decarbonisation of Europe's production and use of energy. However, while it is true that extra network capacity can allow imbalances between demand and the available low carbon power to be shared out spatially and so reduce the need for curtailment of renewables, it has also been observed that enhanced transmission network capacity does not, by itself, guarantee reduction of carbon emissions in the shorter term. This is also dependent on the relative position in the 'merit order' of gas-fired and coal- or lignite-fired generation. (Extra transmission capacity might simply allow cheap coal and lignite in the East of Europe to displace more expensive combined cycle gas turbine plant in the West)[6]. Furthermore, lack of transmission investment would also hinder European Commission ambitions towards a fully integrated and transparent European electricity market and the associated total European social welfare benefits.

At a distribution level, it is not uncommon at present for the connection of low carbon generation to be prevented due to lack of the existing network's ability to accommodate it. In recent months, this has particularly been the case in respect of solar PV in the south of Britain. Some form of distribution network reinforcement is likely to be required but, as we discuss in section 5, we are not persuaded that current regulatory and commercial arrangements concerning distribution network operators are adequate to incentivise the accommodation of distributed generation at least total system cost. In addition, we are not aware of any extensive studies undertaken to assess the likely total cost of distribution network development to facilitate various low carbon futures, some of which might involve significant electrification of heat and vehicle transport[7].

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[5] See, for example, Pudjianto*, et al,* "Asymmetric impacts of European transmission network development towards 2050: Stakeholder assessment based on IRENE-40 scenarios." Energy Economics, 2014.

[6] See Keith Bell, Tom Houghton, *et al*, "Technical and economic impact analysis of the demonstrations in TF2 – Deliverable: D15.2", WP15. Economic impacts of the demonstrations, barriers towards scaling up and solutions, TWENTIES project, 2014, available http://www.twenties-project.eu/node/18

[7] A study commissioned in late 2014 by the Energy Networks Association (ENA) – "Distribution System 2030" – had quite ambitious initial terms of reference and has sought to quantify the benefits likely to accrue from various smarter ways of operating distributions networks – see http://www.smarternetworks.org/Project.aspx?ProjectID=1589 . However, in our opinion, insufficient time or resource was made available for the study for there to be any expectation of it producing any strong conclusions beyond the relative attractiveness of a limited number of network technologies.

4 How can we ensure that a low carbon network is designed and operated fairly and in a way that helps to minimise consumer bills?

Institutional issues

Without major institutional change, delivery of good design, fair operation and minimal cost of a low carbon network depend on present day power industry actors. In our view, some of the key institutional issues affecting them include the following.

- *More innovation on the part of energy retailers*. The number of relatively large users of electrical energy who are ready to be flexible in the timing of their consumption is increasing. Their interactions with existing reserve markets are often facilitated by aggregators and are proving increasingly valuable to the electricity transmission system operator, National Grid. However, to more fully unlock the benefits of flexible demand, the participation of many more users is required, and this arguably needs much more innovation on the part of energy retailers/suppliers in respect of products and prices.
- *Better sharing of information*. Many of the 'smarter' actions that can more fully utilise low carbon generation should take place on the distribution networks. Some of these would increase utilisation of the distribution network infrastructure but require distribution network operators (DNOs) to have better visibility than now of what is happening on their system and what might happen. Other actions that take place at a distribution level will benefit the whole system. If DNOs are to continue to be responsible for operating their systems, this depends on adequate sharing of information and coordination between distribution and transmission and between different transmission licensees.
- *Better understanding of risk*. As already noted, reduction of operational margins and greater dependency on corrective actions is likely to increase the probability that some corrective actions will fail and would lead to greater exposure to disconnections of demand or, on the transmission system, of widespread blackouts; however, the latter incidents, while having a high impact, are very rare and, if system monitoring and control is designed and implemented well, will continue to be rare. Moreover, back-up 'defence' systems can limit the impact if and when they occur.
- *Continued support for network innovation*. This is discussed in section 6.

‘Smart’ meters

One means by which network operators might improve their visibility of all parts of a network and have access to services offered by a multiplicity of actors, including small generators and consumers, is arguably the so-called ‘smart meter’. This promises automated real-time information on power, not just a retrospective manually collected measure of total energy consumed within a period with no indication of when it was consumed. The UK Government plans a roll-out of ‘smart meters’ across the whole of Britain in the next few years[8]. However, the realisation of the potential depends on the specification of the ‘smart meters’. Our understanding is that, while readings will indeed be collected automatically (and should, for example, facilitate easier switching of suppliers), they will collect energy measurements accumulated over half-hour periods[9]. In common with large, half-hourly metered consumers at present, this would allow some degree of time of use pricing which can be used to incentivise consumption at different times. However, it would not, on its own, allow monitoring and compensation for actions that balance out within a half-hour period. That is, a reduction of demand that then increases, say, 10 or 20 minutes later, such as might be the case for refrigeration load, would not be seen and would therefore not be remunerated. In addition, for management of their own networks, DNOs would like to see measurements or power and voltage at least every few minutes; however, we understand that the GB ‘smart meter’ specification does not include measurement of voltage[10]. Moreover, we also understand that the data collected from the standard ‘smart meter’ will be owned by suppliers[11]. It would be easy to speculate that they would want to maximise the value of their data by making it available to others only at a price.

One benefit of automated meter reading should be that customers can switch suppliers more readily and with greater confidence that bills will reconciled correctly. This ought to lead to keener competition in the retail sector. One additional thing that we believe should face as few obstacles as possible is the scope for innovation in respect of genuine ‘smartness’. Because the cost of replacing meters is so high (the majority of the

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[8] Policy in Northern Ireland is as in the rest of the UK but implementation has been delegated to the Northern Ireland Assembly with the Minister for Energy in the province declaring in 2012 that all homes will have them by 2020. However, in practice, our understanding is that only trials have taken place. NIE is still consulting and no costs have yet been included in their price control which runs to 2017. Current meter replacements are still being conducted on a ‘non-smart’ basis.

[9] See p47 of the draft ‘smart meter’ specification: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/381535/SMIP_E2E_SMETS2.pdf

[10] The draft ‘smart meter’ specification requires measurement of active power export and reactive power import/export but not voltage.

[11] Data access and privacy issues are discussed here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/43046/7225-gov-resp-sm-data-access-privacy.pdf

cost is for safe installation, not for the meter itself), we believe it is unrealistic for this to be built into the secure meter 'hard-wired' into an electricity user's electricity supply. Instead, the market should be encouraged to develop devices that can be safely augmented to installed equipment and incorporate as many features as customers choose to have[12].

Reliability of supply

One question that is fundamental to delivery of what electricity users want at least cost is: what is an 'acceptable' level of reliability of supply? As discussed above, a key feature of a 'smarter' grid would seem to be flexible demand. That would require us to distinguish between 'soft' interruptions (actually just reductions not complete interruptions, and authorised under contract) and 'hard' interruptions (complete disconnection, not intended but not 100% avoidable). Otherwise, it seems unlikely that society would accept a reduction in reliability. However, it may also be speculated that many electricity users and their political representatives are unaware of what reliability of supply they can expect now and what the major causes of interruptions are. Further institutional issues are discussed in the next section.

5 How can we ensure that grid connections are readily accessible across the country and that costs are fair?

Transmission connections

Arguably, it is already the case that transmission connections are 'readily accessible' and costs are 'fair'. The transmission system operator, in liaison with the relevant transmission owner, is obliged to make an offer of a connection to the transmission system within 3 months of receipt of a valid application and the cost of making an application is regulated[13]. In addition, local connection works are 'contestable', i.e. the applicant is not forced to buy the service from the incumbent transmission owner. However, there is no guarantee that an offer will be for an immediate connection or that the connection, when it is made, will be cheap. Delays can occur (a) for planning consents for local connections or (b) for 'deeper' reinforcements to be identified, approved, implemented (the last of these also dependent on planning as well as manufacture, construction and commissioning) and paid for.

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[12] For further discussion, see http://www.ukerc.ac.uk/news/smart-meters-and-untidy-thinking-a-blog-from-ukerc-co-director-keith-bell.html

[13] See http://www2.nationalgrid.com/uk/services/electricity-connections/new-connection/

The ‘Security and Quality of Supply Standard’ (SQSS[14]) provides a common, published basis for determining what features are required of a transmission connection and deeper reinforcements, and hence their costs and delivery timescales. Data exchange rules and the technical performance required of, in particular, generators connecting to the transmission system are documented in The Grid Code (which is publicly accessible[15]).

The costs of the ‘deeper’ transmission system, i.e. the main, shared infrastructure, are recovered via the Transmission Network Use of System (TNUoS) charge[16]. The basis for the way in which it is calculated for different users has been the subject of a review by Ofgem in recent years – ‘Project TransmiT’[17] – and has led to approval of a change argued to better recognise the different drivers for transmission expansion arising from different patterns of use of the system by different generators[18]. One effect of that has been to reduce the charges levied on wind farms in the locations that are most remote from the main demand centres while still allowing demand in the remoter areas to pay less than demand in the biggest centres[19]. It is our understanding that, while many transmission users would not regard the new approach as perfect, most would regard it as fairer than the previous one.

Distribution connections

Inevitably, the generators or loads for which owners seek connections to a distribution network are smaller than those for which a transmission connection would be more suited and, as a consequence, the owners or developers may lack the resources – people, money and expertise – that are mustered behind bigger projects. It may therefore be argued that technical standards, however rationally set, represent a greater barrier than they would for transmission. We would argue that it certainly does not help that, in contrast to transmission, those standards are not published and must be bought at a significant fee from the Energy Networks Association[20].

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[14] See http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/System-Security-and-Quality-of-Supply-Standards/

[15] See http://www2.nationalgrid.com/uk/industry-information/electricity-codes/grid-code/the-grid-code/

[16] See http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-network-use-of-system-charges/

[17] See https://www.ofgem.gov.uk/electricity/transmission-networks/charging/project-transmit

[18] For discussion, see https://www.ofgem.gov.uk/publications-and-updates/academic-review-transmission-charging-arrangements-universities-strathclyde-and-birmingham

[19] Scotland is an example of a location where generation side users of the transmission system tend to pay higher TNUoS charges than in most other areas but demand side users pay less.

[20] See http://www.energynetworks.org/electricity/engineering/engineering-documents/engineering-documents-overview.html

Historically, where network capacity has been judged by a DNO to be insufficient to accommodate a new connection without breach of network limits at any time, the DNO has required reinforcements to be done as a precondition of connection with those reinforcements paid in large part by the connecting party[21] and the specification such that the operation of the connected equipment does not need to be monitored, i.e. the DNO can 'fit and forget' the connection.

The tendency for 'fit and forget' connection of generation embedded within the distribution networks[22] is a reflection of the relative lack of observability and controllability on the present day distribution networks and is only now being slowly changed to recognise that network limits only become binding – and, hence require action on the part of the operator, or, in the longer term, the network developer – at certain times. It is our view that active management of distribution networks will often provide a more cost-effective solution to the accommodation of new generation than the network reinforcements that 'fit and forget' would entail. However, we believe that the current immaturity of commercial frameworks around distribution connection and operation not only of generation but also of flexible demand and inconsistency between DNOs hinders the discovery of economic solutions and fair treatment of all network users or potential users. One outcome is that large costs, significant risks or both are placed on generation developers often with the result that developments do not go ahead. From a whole energy system point of view this might, on occasions, be the 'right' outcome in respect of a development at a particular location provided other more economic locations are developed. However, if an increase in embedded generation capacity as a whole is not to be held back, there is in our view a need for clear and consistent commercial frameworks that adequately reveal the costs and benefits of network reinforcements and active distribution network management and share risks and rewards between parties connected to the network and the DNO.

In saying the above, it should be recognised that DNOs have been subject to many years of price control by Ofgem and its predecessor that have had the effect of driving down DNO costs. A DNO might argue that more active network management and more considered processing of connection applications are new duties that have not been provided for in their remuneration arrangements. On the other hand, Ofgem might argue that DNOs have been free rein to make arguments for extra allowances to which Ofgem would give due consideration.

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[21] See https://www.ofgem.gov.uk/electricity/distribution-networks/charging-arrangements

[22] Generation embedded with a distribution network is also known as 'distributed generation' (DG).

6 What are the key technologies available today and how effectively do Government and Ofgem incentivise innovation and development of the grid and grid technologies?

Grid development incentives

In section 3, we expressed the view that a future low carbon network is likely to depend on investment in 'primary' assets – those that that generate, transmit or distribute power. However, it has been argued by some that incentives towards 'development of the grid' are too strong[23]. This is predicated on the idea that, because the regulated network licensees gain an income proportional to the value of their asset base, they will naturally seek to increase that asset base by identifying needs for reinforcement that might not really be there or 'gold plating' the network. However, it is also the case that asset values are only added to the regulated asset base if Ofgem deems them to have been legitimately incurred in accordance with the network licences, a key condition of which is an 'economic and efficient' network. Moreover, the capital to fund investments still needs to be raised and the majority of income is generally only reset at the end of a price control period (which used to be 5 years and is now 8 years); thus, it may be supposed that the network licensees prefer not to incur capital expenditure at the beginning of a price control period. On the other hand, given constraints in the supply chain and incentives on a system operator to reduce the number and duration of construction outages, excessive delay may prevent projects from being delivered before they should be and so risk non-compliance with the licence in the direction of apparent under-investment.

Key technologies

A number of key technologies that might permit increased utilisation of the electricity system infrastructure have been mentioned in section 3, e.g. real-time ratings and associated forecasting; power electronics and HVDC, notably more advanced control and higher ratings for transmission applications and lower costs for distribution applications; phase shifting transformers, series compensation and their coordinated

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[23] See Imperial College London and University of Cambridge, "Integrated Transmission Planning and Regulation Project: Review of System Planning and Delivery" available here: https://www.ofgem.gov.uk/publications-and-updates/integrated-transmission-planning-and-regulation-project-emerging-thinking

use; and phasor measurement units. To these might be added increased current and voltage ratings for underground or undersea cables; less visually intrusive but not excessively costly designs of towers for overhead lines; reliable ‘plug and play’ special protection schemes or active network management; automatic generation control; integrated monitoring, protection, remote control and data collection for distribution networks; integrated condition monitoring and communication; fault current limiters; and cheaper forms of energy storage capable of converting into electricity. However, the required technologies also include new software tools to manage data, model system performance and provide decision support to system operators[24].

Innovation incentives

It has been documented that, in the years following liberalisation of the electricity supply industry in Britain, the industry’s expenditure on research and development decline dramatically, particularly in the distribution sector[25]. Since then, Ofgem has introduced a number of schemes designed to encourage the network licensees – electricity and gas, transmission and distribution – to innovate and to be free to use a certain amount of customers’ money to do so provided certain conditions are met[26]. We believe Ofgem is to be highly commended for this initiative manifested through the Innovation Funding Incentive (IFI), the Low Carbon Networks Fund (LCNF), the Network Innovation Allowance (NIA) and the Network Innovation Competition (NIC). The success of these schemes can be seen through the increased investment in innovation. However,

- in our view, they have not always been used as effectively as they could be;
- we understand that they are now under threat.

Given the licence condition towards ‘economic and efficient’ networks, various income adjustors introduced by Ofgem under the new RIIO regime to reward ‘good’ performance and the promise offered by the various technologies mentioned above, it might asked why the network licensees need any innovation incentives. Indeed, that is likely to be behind what we understand to be Ofgem’s view that the current explicit innovation incentives – not only NIC but also NIA[27] – can be stopped with no detrimental effect for consumers. Leaving aside the particular features of NIA and NIC, as a general principle, we believe that would be a mistake.

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[24] See http://www.theiet.org/sectors/energy/resources/modelling-reports/index.cfm

[25] See, for example, Tooraj Jamasb, Michael G. Pollitt, “Why and how to subsidise energy R+D: Lessons from the collapse and recovery of electricity innovation in the UK”, *Energy Policy*, Volume 83, August 2015, Pages 197-205

[26] See https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation

[27] The Network Innovation Competition (NIC) differs from the Network Innovation Allowance (NIA) in that, in NIC, funds are awarded to large projects through a competitive process are aimed at technologies with quite high ‘technology readiness levels’ (TRLs).

The ‘economic and efficient’ licence condition has been in place since liberalisation. Why, then, was it necessary to introduce IFI, LCNF, NIA and NIC? In our view, the answer concerns risk and uncertainty.

For the most part, the network licensees are seen by their shareholders, i.e. by investors, as low risk investments with unspectacular but safe returns. They are not exposed to competitive markets (except insofar as Ofgem seeks to compare one licensee with another in price reviews and to reward ‘good’ performers and punish ‘bad’ ones); their income is largely fixed and well-known quite far in advance. However, their scope for making very large profits through some kind of competitive advantage is limited. In the past, it has also tended to be that their scope for increasing profit through cost reduction was limited as Ofgem, acting in way that it saw as best for consumers, tended to take a large part of that cost reduction at the next price control as part of the ‘base line’, i.e. to give much of the benefit to consumers (meaning less benefit for shareholders).

One feature of any innovation is that, by definition, it is new. Because it is new, it is unfamiliar and, hence, there seems to be a chance that it will not work as expected, will save less money than expected or cost more than expected. In other words, there is risk and uncertainty.

Would the network licensees’ investors welcome the licensees becoming bigger risk takers? Would, in the end, Ofgem welcome it? At the extreme, some innovation might lead to some unreliability of supply or failure to facilitate competition in the electricity market. (‘Security of supply’ and facilitation of the market are also network licence conditions). Even if that does not happen, a market perception of risk would lead to an increase in the licensees’ cost of borrowing and, as a consequence, the cost of network investments increasing.

In our view, where IFI, LCNF, NIA and NIC have been successful has been in giving the licensees scope to address uncertainty, to explore an idea and gain knowledge about it before committing to it fully; in other words, to undertake research and development (R&D) that the companies’ response to the regulatory regime – the squeezing downwards of costs – would not otherwise entertain. If done well, the R&D would be of long term benefit to consumers as innovations could be identified in which there can be confidence, not least with respect to delivering the core service at least cost.
Where, in our view, the innovation schemes have not been done well has been due, in particular, to the following:

a) The licensees have interpreted ‘success’ of an innovation project as only arising if the idea being investigated is adopted as business as usual. This has the result, firstly, that projects are commissioned only if they are judged to have a high chance of 'success', in which case there would seem to be relatively little doubt about the outcome and one wonders why innovation allowance money – designed to account for risk and uncertainty – was needed; and, secondly, negative or inconclusive results can tend to be hidden even when they are quite understandable and contain important learning. Instead, in our view, 'success' should concern the *quality of the evidence gained* either that it should be adopted (and how) or that it should not (if certain conditions are not met). This implies that a robust, informed judgement regarding the proposed innovation can now be made.

b) The network licensees have, over the last 25 years, broadly forgotten how to do, manage or report R&D with the result that experiments are not always well designed and reports sometimes fail to provide the means by which others might test the results and conclusions.[28]

c) A failure to recognise that uncertainty is not just something that prevents exploitation of an opportunity but might instead concern a threat that is not well understood. An example of the former might be real-time thermal ratings: how do we do it, what does it cost, what are the risks, what are the benefits? An example of the latter is the public's perception of electromagnetic fields. There is no clear, consistent evidence of a detrimental effect on health but some people believe there is, nonetheless, a detrimental effect. There is clearly a need to keep investigating, but who pays for it? Other examples are: the possibility that a power system with too little inertia will be inoperable – we do not yet know if that is true or how little inertia is too little; and, what would be impact of use of SF_6 gas being banned[29]?

Government support for innovation

In addition to the support for innovation made available through Ofgem, the UK Government plays an important role. In respect of taking technologies through to demonstration and deployment, initiatives through The Carbon Trust and InnovateUK are significant. However, more basic research and development tends to be funded

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[28] We believe there is now evidence that at least some network licensees are becoming better at managing and reporting R&D. The quality of published outputs has improved through the lifespan of the LCNF.

[29] Sulphur hexafluoride – SF_6 – is an excellent electrical insulator widely used in power system switchgear to aid the extinction of arcs created by the isolation of short circuit faults, and increasingly used in compact high voltage substations. It is also an extremely potent greenhouse gas.

through the research councils, in particular the Engineering and Physical Sciences Research Council (EPSRC), and undertaken at universities. The European Commission also plays an important part in supporting research, development and demonstration although UK industry and academic actors arguably take less advantage of this than they could.

Universities in the UK can play a key role in helping the power companies transition to the new, low carbon world, delivering both ideas and people to the energy industry. This requires not only individual academics who meet standard university performance metrics by churning out learned papers but teams that are capable of helping industry navigate the challenges facing them, resolve key uncertainties and adopt appropriate innovations. This requires considerable investment of time and effort in close industry engagement and support for building and retaining capacity, not least in terms of expert research personnel. However, the insistence by Ofgem that NIA and NIC are project specific, EPSRC's short-term funding of more basic research through individual projects and EPSRC's often unreliable review process make this challenging.

7 What impact will changes to the electricity system have on the role of National Grid and the Distribution Network Operators?

System operation

Because a power system is a single, dynamic, non-linear system in which a condition can be tipped into instability within moments and a system collapse take place within seconds, we find it difficult to envisage the GB system being operated more effectively by multiple system operators than by one. However, as it does now, successful system operation depends on successful interaction between different parties. At present, that primarily means large generators providing ancillary services, procured by National Grid. In future, it should involve many more providers including flexible demand. Given the location of many of those future active participants, an extended role for DNOs seems essential. Although aggregators might interact with electricity users and organise the availability of responses or re-scheduled consumption in order to contribute to balancing of the system as a whole, distribution network limits still need to be respected. One way in which possible conflicts between required whole system actions and those required on a local network might be avoided would be through a hierarchical control in which procurement of margin and actuation of responses from actors within a given distribution network area are the responsibility of the DNO which then operates as a 'distribution *system* operator'. The critical dimension in this will be the correct management of the electrical interface between different levels of the hierarchy, e.g. between transmission and distribution, with definition, in real time, of the prevailing and expected power transfer and the margin for increases and decreases, all quantified by the operator of the lower level knowing what is active on its own network. Although at least one LCNF project has begun to explore some of these ideas[30], DNOs' culture and expertise would need to change significantly before the vision can be realised. (See section 5 for further discussion of DNOs). As now, the interactions between different items of equipment owned by different parties are likely to depend on appropriate technical standards[31].

System planning and development

In respect of planning and development of the system, changes are already afoot. Purchase of long-term services by a single buyer from generators has recently been introduced with two auction mechanisms: one for energy from low carbon sources, the other for generation capacity available at times of peak demand. Now, as part of 'Integrated Transmission Planning and Regulation' (ITPR), Ofgem is seeking to introduce the idea, in effect, of the single GB transmission system operator buying significant instances of new transmission network capacity through a tendering process (as distinct from the regional transmission owners deciding on additional capacity, designing it and then buying the equipment for it and the construction of it through a tendering process)[32]. How this works and whether it will really bring efficiencies remains to be seen. It may be noted that Ofgem's initiative does not extend to coordination of network investment between transmission and distribution, aspects of which are: whether the market signals, not least use of system charges, correctly incentivise generators to connect to transmission or distribution; whether the network design standards that apply to 132kV in Scotland are appropriate; and what impacts aggregated, individually relatively small changes to demand and generation on the distribution network might have on transmission and where those impacts would best be managed.

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[30] See outputs to date from the 'Accelerating Renewable Connections' (ARC) project, e.g. here http://www.spenergynetworks.co.uk/pages/arc_accelerating_renewable_connections.asp , and proposals for a follow-on project based on ideas from the University of Strathclyde, 'Evolution': https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/electricity-network-innovation-competition

[31] The IET has suggested that increasingly rapid changes to the technologies connected to the power system will make it difficult to ensure that standards are updated appropriately and remain fit for purpose. They have proposed that a new role of 'system architect' would have responsibility for ensuring alignment of standards. See http://www.theiet.org/factfiles/energy/brit-power-page.cfm

[32] See https://www.ofgem.gov.uk/electricity/transmission-networks/integrated-transmission-planning-and-regulation

Competition in provision of services

Ofgem has long regarded it as important to extend the role of competition in the electricity system. It has favoured 'merchant' development of interconnection capacity where private investors both identify a need or opportunity for capacity and deliver it. However, such an approach tends to under-deliver capacity relative to the theoretical socio-economic optimum. (When capacity is scarce, risk is limited for the investor and income maximised). Partly for this reason, many of Ofgem's European counterparts favour development by a regulated transmission system operator (TSO).

Given that the function of an interconnector can be seen as the spatial redistribution of imbalances between generation and demand, an analogy can be seen with storage. Pumped storage facilities, capable of converting both to and from electricity, were originally seen, alongside network capacity, as services to be developed and used by a TSO. However, in the 1990s, Ofgem required divestment of pumped storage capacity by National Grid. To an extent, the separation of transmission ownership (TO) from system operation (SO) could be seen in the same light. One outcome of such a separation could be argued to be that the system operator will now lack full information on the costs and benefits of the full range of options – including network expansion – to manage the system in the medium to long term. Following a split of TO from SO alongside the established separation of generation from network ownership and operation, if the system operator is to procure appropriate services correctly, even if they are offered as different products, it should be possible for the SO to consider providers in light of all the services they are offering and not each service in isolation. For example, a particular generator might seem expensive in respect of capacity in the capacity market alone, but a capacity contract might be efficient given (a) the frequency service that the generator offers and (b) the way its operation would avoid a need for network reinforcement (which would depend on a TO)[33].

8 What lessons can be learnt from low carbon electricity grids from other countries?

Other countries in Europe are arguably much further down the road to decarbonisation of their electricity systems than Britain. These include:

- France, with most of its electrical energy coming from nuclear and hydro power;
- Spain, with a high penetration of wind and solar power;

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[33] At least in respect of the various services that a generator might offer, one simple step might be to align the tendering timetables for different services so that they can be considered together.

- Denmark, with a longstanding, planned commitment to decarbonisation of the whole energy system, not only electricity, significant experience of combined heat and power and district heating as well as wind, and of different funding mechanisms;
- the island of Ireland, like Britain, a relatively small power system 'synchronous area' but with proportionally much more wind generation than Britain.

In France, although the electricity system is part of the single, European synchronous area and so experiences less variability of system frequency than we do in Britain and is well connected electrically with its neighbours, imbalances of power do still need to be managed. It has access to significant and highly flexible hydro resources but also requires at least some of its nuclear capacity to be capable of flexing its output. There is also significant electric heating load and this contributes to system balancing through a long-established, centrally managed load switching scheme. In addition, somewhat in contrast to the network licensees in Britain, the transmission system operator, RTE, has made it a priority to retain research and development and advanced analytical skills within the company.

In Spain, although, like France, a part of the European synchronous area, there is very limited interconnection to the rest of the continent meaning that potential power imbalances arising from variability of wind and solar power and demand need to be carefully managed. To that end, a few years ago the Spanish system operator, REE, established a dedicated control centre for the management of renewables, CECRE[34].
In Ireland, the system operator and the government seem to have been much more systematic in assessing the challenges and potential solutions associated with the operation of many wind turbines than we have in Britain and have sought the best consultants from around Europe to carry out studies and make recommendations[35]. They have then looked globally for appropriate new system management software tools.

Outside Europe, the PJM regional transmission organisation in the Eastern United States is widely regarded as operating an exemplar market for flexible demand[36]. It has indeed attracted a large number of participants adding to a significant total volume of reserve made available to the system operator. However, it should also be noted that the initiative has not been without its problems, e.g. in the first rounds of some of the markets, promised responses not being delivered; being subject to a legal challenge;

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[34] See http://www.ree.es/en/activities/operation-of-the-electricity-system/control-centre-renewable-energies

[35] For further information on the accommodation of renewables in Ireland, see http://www.eirgrid.com/operations/ds3/

[36] See http://www.pjm.com/markets-and-operations/demand-response.aspx

and, more recently, a recognition that at least one of the products was inadequately defined to contribute to management of imbalance risks arising in the winter[37].

9 Conclusions

This paper has discussed networks to facilitate use of energy from low carbon sources. A future 'low carbon network' need not concern only electricity – meeting future energy needs in a manner compliant with a particular carbon budget must address the demands of heat and transport as well as electricity. However, electricity's role is likely to be critical because of the flexibility of use of electricity, the options for its generation and its current cost-effectiveness as an energy vector relative to, for example, hydrogen. Although heat networks – at present, little used in Britain – may become important and technologies such as micro combined heat and power (CHP) promise efficiency benefits without totally eliminating carbon emissions, to large extent a 'low carbon network' means an electricity network.

Britain's existing electricity system has been successful at managing potential imbalances between demand for power and the available generation, facilitating the electricity market and delivering what is broadly regarded as an acceptable level of reliability of supply. However, the variability and uncertainty of much renewable generation, the reduction of system inertia and, unless designed with extra, costly capability, the relative inflexibility of nuclear power and fossil fuelled plant with carbon capture and storage, will make system balancing more challenging in future.
Low carbon generation, in large part, can be expected to connect at the geographical or electrical periphery of the existing system, e.g. wind and nuclear power in locations that are remote from population centres, and solar PV within the lower voltage distribution networks. The present day electricity networks were not designed for much, if any, additional generation at such locations.

In order to both accommodate additional low carbon generation and facilitate European Commission ambitions for a transparent, integrated European electricity market, a need for additional 'primary' electricity network assets – i.e. those that generate, transmit or distribute power – is very unlikely to be avoidable. Extra network capacity allows power

[37] The main demand response product at the time gave the system operator to curtail demand only in summer. Given the high level of cooling demand in summer, it provides a useful service. However, it is also likely that curtailment of cooling in summer will be made more available to the system operator than curtailment of heating in winter. For further background on PJM's demand response schemes, see, for example, Craig Glazer, "Demand Response in PJM: Past Successes and the Murky Legal Future of Demand Response", July 2014. Meanwhile, it should also be noted that it may be easier and more socially acceptable to procure demand response to reduce summer cooling load than to reduce winter heating load.

imbalances to be shared spatially and so promises to reduce curtailment of renewables. However, in the short term, if coal or lignite remain cheaper to burn for the generation of electricity than gas, the carbon reduction benefits of enhanced transmission network capacity might not be realised.

It ought to be possible to reduce the extent of need for new primary system capacity through 'smarter' system operation which depends on more accurate and wider reaching network monitoring than we have at present. Although 'corrective' actions to manage unplanned disturbances to the system are already widely used, 'smarter' system operation also depends on their much more extensive use, particularly in order to exploit the potential benefits of flexible demand. Key technologies include real-time ratings and associated forecasting; power electronics and HVDC, notably more advanced control and higher ratings for transmission applications and lower costs for distribution applications. They also include new software tools to manage data, model system performance and provide decision support to system operators.

'Smarter' system operation depends, crucially, on adequate expertise within the industry. Moreover, we see a number of institutional issues, including: a need for greater innovation on the part of energy retailers (suppliers); better sharing of information, in particular between distribution network operators (DNOs) and transmission licensees and between transmission licensees; and a need for a better understanding of reliability of supply and what is acceptable with distinctions made between 'soft' and 'hard' interruptions and the risk of major events as a possible consequence of 'smarter' system operation.

We feel there is a need for a clearer understanding of what 'smart meters' might be and a more effective implementation than we understand to be currently planned, with greater scope for innovation in respect of the 'smartness' of devices used by consumers. We see there being scope for improvement in the facilitation of new connections to the electricity networks and regard the greatest scope for improvement as being in respect of connections to the distribution networks. In particular, we believe that arrangements should be developed that move DNOs away from 'fit and forget' approaches and towards more active network management, and that provide a basis for rational comparison of network reinforcement and generation curtailment options in such a way that does not place all the risk on parties seeking to connect to the network, and shares costs fairly between different connectees.

Given what we see as an unavoidable need for at least some network development to deliver a lower carbon energy system, we believe that caution should be exercised with respect to claims that grid development incentives are currently too strong.
We foresee greater use of controls located on the distribution networks, both for management of distribution network limits and for operation of the power system as a

whole. This would require DNOs to act more as 'distribution *system* operators' and a significant change in their culture and levels of expertise but also requires adequate coordination between distribution and transmission. One option to achieve that would be through an operational hierarchy with clearly defined limits and capabilities at the boundaries between operational entities.

We believe there is scope for rationalisation of the different rules, conventions and incentives relating to distribution and transmission in order to more consistently give the correct signals to generation developers with respect to appropriate locations for development and, to the network licensees, facilitation of connection.

System operation depends on different services – many of them referred to as 'ancillary' services – offered by generators and, potentially, users of electricity and owners of storage. While Britain currently has some relatively well-developed markets for these services, we believe that benefits might arise from their better alignment allowing a package of capabilities to be assessed in respect of their overall cost-effectiveness.
In our view, the various network innovation schemes established by Ofgem have been very worthwhile. Although we believe that their implementation and the conduct of 'innovation' – in particular, research and development (R&D) and subsequent building on learning – could be improved, we believe it would be a mistake, as we understand Ofgem to be considering, to withdraw explicit financial support for R&D led or commissioned by network licensees. Moreover, the Government needs to continue to support innovation and R&D, not least through the development and retention of capacity and expertise in the UK's universities.

Finally, we believe that useful insights can be gained from the experiences of, in particular, the following countries:

- France, with most of its electrical energy coming from nuclear and hydro power;
- Spain, with a high penetration of wind and solar power;
- Denmark, with a longstanding, planned commitment to decarbonisation of the whole energy system (not only electricity), significant experience of combined heat and power and district heating as well as wind, and of different funding mechanisms;
- the island of Ireland, like Britain, having a relatively small power system 'synchronous area' but with proportionally much more wind generation than Britain.

Appendix: The ECC Select Committee Inquiry

In September 2015, the House of Commons Select Committee on Energy and Climate Change (ECC) initiated an inquiry into 'low carbon networks' with the aim of identifying "what changes are required from today's electricity infrastructure to build a low carbon, flexible and fair network". According the Committee,

> The UK electricity infrastructure is ageing and substantial investment will be required to upgrade the network (both transmission and distribution) to address today and tomorrow's energy system needs. As low carbon technologies and distributed energy play a greater role, the move towards a smarter, more localised and diverse system presents both challenges and opportunities. Ensuring this transition occurs in a cost-effective way while maintaining system security and stability is challenging, and the Government needs to ensure that policies allow proper planning, testing and investment to take place. It will require addressing all elements of the energy infrastructure, including those on the demand side of the meter, engaging with customers and addressing their needs.

For further background on the Committee's inquiry and, when they are published, written responses, see http://www.parliament.uk/business/committees/committees-a-z/commons-select/energy-and-climate-change-committee/inquiries/