Energy Policy 113 (2018) 765–777

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Delivering a highly distributed electricity system: Technical, regulatory and policy challenges

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ARTICLE INFO

Keywords:
Electricity system planning
Electricity system operation
Distributed energy resources
Distributed generation
Electricity market design
Regulation

ABSTRACT

This paper discusses the technical, regulatory and policy challenges inherent in planning and operating power systems with high penetrations of Distributed Energy Resources (DER): generators, flexible demand and energy storage connected within electricity distribution networks. Many liberalised electricity systems worldwide are seeing growth in DER including significant capacities of distributed renewable generation. The paper starts from the premise that optimal distribution networks are those that satisfy the objective of a lowest cost power system whilst meeting customers' expectations of reliability and societal desire for sustainability. It highlights major challenges that policy makers face in respect of market and regulatory arrangements that support energy and flexibility provision from a large number of small, variable and often uncertain resources. These challenges include the need to respect the technical limits of the system and ensure its operability, development of well-designed mechanisms to support innovation, and an appropriate share of risk between market actors. A key contribution of the paper is to discuss the opportunities offered by more active distribution system operation as a substitute for capital investment and its regulatory and policy implications. Finally, the paper presents priorities for policy to facilitate a highly distributed electricity system.

1. Introduction

A decarbonised electricity sector serving not only the current demand for electrical energy but increased electrified heating, cooling and transport will be extremely important in achieving the sustainability objectives of energy policy at lowest cost. Decarbonisation is driving electricity systems in many countries towards decentralisation, with a growth in Distributed Energy Resources (DER), a process that is likely to continue as greater penetrations of storage, electric vehicles, and new forms of flexible demand connect to the network. In order to ensure that the electricity system is able to support wider energy system objectives effectively, the way the system is planned, operated and regulated must be reviewed with policy makers establishing an adequate environment for investment and operational decision making by industry and individuals alike.

In contrast to the planning and operation of electricity generation and storage in liberalised markets, the planning and operation of power networks have long been regarded as 'natural monopoly' activities. Although various regulatory initiatives have sought to introduce stronger elements of competition into the provision of network capacity, strong regulatory frameworks and structures for network planning and operation still seem to be necessary. Established approaches are, in general, little different from those that existed pre-liberalisation and concern (i) a separation in network ownership between regional networks – distribution – and interconnected networks that cover multiple regions or whole countries – transmission; and (ii) active real-time system operation including coordinated final dispatch of generation. The historical predominance of large transmission connected generation has meant that the operation of electricity markets, active control of the power network and the provision of flexibility in the generation and demand or energy have been tended to be restricted to the transmission system network and directly connected customers, with distribution providing passive network capacity between the transmission network and end users.

Three changing characteristics of the power system are leading to a requirement for a greater role for electricity generation and flexibly operated assets connected to distribution, and by extension greater coordination between transmission and distribution:

1. an increase in the proportion of generation and flexible resources to be found connected to the distribution, rather than transmission, networks;
2. an increasing contribution to energy (and potentially flexibility) provision from *uncertain, weather dependent renewable generators*

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https://doi.org/10.1016/j.enpol.2017.11.039
Received 30 May 2017; Received in revised form 11 October 2017; Accepted 20 November 2017

connected at either transmission or distribution voltages which drives an increased requirement for flexibility through reserve services over time scales of an hour and longer; and
3. a change in *system dynamic characteristics* initially due to the reduction of synchronous generation caused by the closure of large traditional power stations which drives an increased requirement for flexibility through response services over times scales of a few seconds or less.

Each of these distinct but interrelated changes has profound ramifications for the future development and operation of the power system but have been hardly discussed in the literature to date in respect of the regulatory and policy implications. This paper's contribution is to make an original use of both engineering knowledge and reflections on current regulatory arrangements from a number of international examples to highlight a range of issues associated with these challenges and some of the limited responses to them to date. It reviews some of the fundamental aims that drive power system planning and development at different voltage levels and discusses various approaches that might support the efficient planning and operation of an electricity system with high DER penetrations together with the policy requirements needed to enable these. It goes on to address the challenges faced in achieving such aims and discusses a number of new and existing practices that will impact on this transition. In particular, it highlights some key changes that are likely to be needed in respect of the way that electric power systems are regulated and the arrangements that govern relationships between, in particular, parties responsible for different aspects of the network infrastructure and parties connected to and using that infrastructure. Finally, it presents a list of priorities for future systems aimed at attaining the optimal combination of DER, operational control and infrastructure investment and discusses the policy changes needed to achieve this.

2. Background and literature review

The term DER covers a range of providers of energy and flexibility connected to electrical distribution networks; subsets include distributed generators (DG), distributed storage, various forms of demand-side flexibility and more technical resources such as 'reactive power providers'. For many decades, the majority of electricity generation connected to large power systems has been connected to the transmission networks. However, the drive towards decarbonisation, often incentivised by financial support mechanisms such as feed-in tariffs or tax breaks, is changing this situation. Table 1 gives some estimates of installed distributed generation capacity compared with peak demand for a number of electricity systems. Germany is an example of a country with a DG capacity in excess of its peak demand. The Republic of Ireland (which forms a single system along with Northern Ireland) and Great Britain are islanded systems where the technical challenges associated with whole system stability are more acute. The effects of increased DG penetration on the distribution network itself include: more variable power flows within distribution networks and between distribution and transmission; the potential need for network upgrades to facilitate export from, as well as import to, the distribution network; and high voltage issues associated with distributed generation connected to low and medium voltage feeders (CIGRE, 2014). Managing these impacts can be achieved through a combination of capital network investment – building new network capacity - or though making use of flexibility from DER, including the DG itself.

Table 1
Estimated capacity of distributed Generation and peak demand.

System	Year of Estimate	Capacity of Distributed Generation (GW)	Peak Demand (GW)
GB[a]	2016	23	61
Germany[b]	2015[2]	89	86
California[c]	2016	10	61
Republic of Ireland[d]	2017	1.9	5.0

Notes:
[a] GB data from Future Energy Scenarios (National Grid, 2017).
[b] German distributed generation figure only includes renewable DG (Federal Ministry for Economic Affairs and Energy, 2016); peak demand estimate for 2013 from IEA (2013).
[c] California distributed generation data from California Energy Commission (2017a). Peak Demand from California Energy Commission (2017b).
[d] Republic of Ireland data from the All-Ireland Generation Capacity Statement (Erigrid, 2017) and from ESB Networks (2017).

A second class of impacts occur because distributed generation displaces transmission connected generation, changing the way in which system-wide flexibility services are delivered. When large, synchronous generation plant is replaced by power sources connected via power electronic interfaces, this also changes the requirement for these services. The potential for DER to support system operation through the provision of flexibility has been highlighted in a number of recent reports (e.g. MIT, 2016; The IET, 2016; EPRI, 2017).

Understanding and analysing the challenges posed by a more distributed electricity system requires a reappraisal of the fundamental objective of the power system planning and operation within the context of a highly distributed system.

2.1. Power system planning and operation: the objective

One way to understand the fundamental objective in planning and operating a power system is as a *cost minimisation* within particular constraints which include, for example, limits on carbon emissions and requirements for reliability of supply (Mancarella et al., 2016). The costs which must be considered include: capital investment for generation, network assets and flexibility options such as storage; operational costs associated with managing network congestion; the cost of network losses; and the cost of ancillary services required to provide sufficient reliability and quality of supply. If emissions are not set as a constraint, environmental costs such as carbon prices will be included in the objective.

A particular challenge in liberalised electricity supply industries in which ownership and operation of generation is separated from that of networks lies in achieving a coordination between generation and network planning and operation that gives a minimum whole electricity system cost while satisfying energy users' reliability requirements. This is commonly interpreted as requiring correct signals to generators, storage operators and demand reflecting the costs of the network and of system operation (Biggar, 2014). At transmission level in some jurisdictions including many North American networks (for example see Nappu et al., 2014) these take the form of Locational Marginal Prices in the real-time or near real-time wholesale market with a potentially unique price at every node of the network, the locational variations reflecting the availability at that time of network capacity to physically support transactions. A less-granular approach is taken in markets with zonal pricing, for example Nordpool covering most of Scandinavia (Bjørndal et al., 2013). In others, such as GB, the majority of energy trading is uncoordinated and locational signals are given annually via network use of system charges (Bell et al., 2011).

Where significant DG penetration is part of a rational response to a particular overall set of incentives and price signals, the objective of distribution planning and operation is to minimise the cost of distribution network reinforcement and operational actions. Theoretically, the latter includes some quantification of the cost of unreliability of supply to energy users though, in practice, it is often the case that a certain level of reliability is set as a constraint. It also includes the impact of curtailment of DG that wishes to generate but, due to network constraints, cannot, at least not fully.

At low DG penetrations, new connections can often be made without a need for deeper network reinforcement. As the volume of

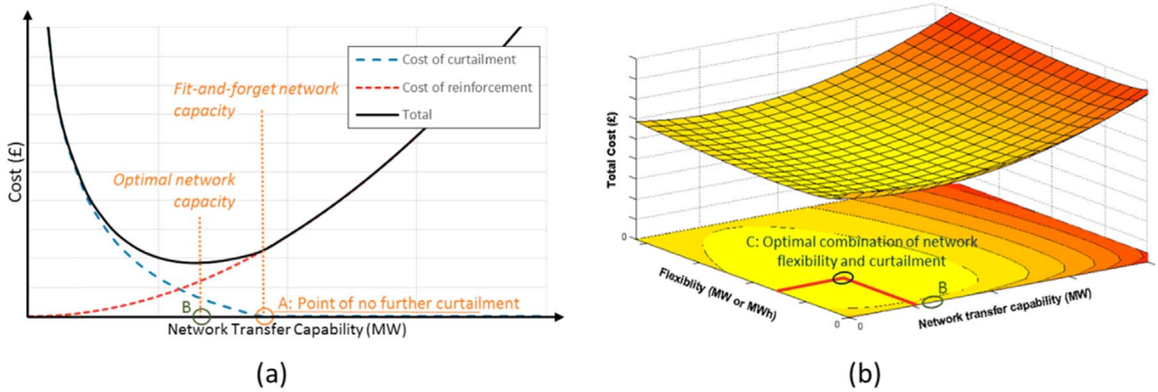

Fig. 1. The economically optimal combination of (a) network capacity and DG curtailment; and (b) network capacity, DG curtailment and DER flexibility provision.

connected DG increases, the amount of available network capacity becomes exhausted and, if the DG is to be accommodated, some reinforcement appears to become necessary. Similar is true in respect of growth of electricity demand for heating and transport.

Traditional distribution network practice is often described as 'fit and forget' (CIGRE, 2014), i.e. network capacity should be such that generation is generally curtailed only if the connection to it is entirely lost and all demand should be met with at least a particular, high probability of success. Among other things, this enables operation of distribution networks with small numbers of control room staff and passive operation with little need for regular updates of network configuration or control targets, e.g. automatic voltage control settings. However, this approach is unlikely to minimise total cost. Both demand and the power available from generation vary in time. At lower levels of DG penetration, restriction of DG output to respect network limits is likely to be both partial and temporary. Provided generation curtailment is costed correctly, it can help to reveal an appropriate level of network reinforcement which will be less than that under fit and forget (Ault et al., 2007). Fig. 1 shows that the optimal level of network capacity is that at which the incremental cost of network capacity equals the incremental value of avoided DG curtailment i.e. where the gradient of the cost of curtailment and cost of reinforcements are equal in magnitude and opposite in sign. Fit and forget ensures zero curtailment of DG, shown as Point A in Fig. 1(a).

The integration of flexibility from an array of DER resources adds a further dimension to the optimisation problem. For example, flexible demand or storage can reduce either DG curtailment or network capacity requirements and the optimal solution is now the lowest cost combination of all three. Fig. 1(b) illustrates this and shows the optimal solution that should be attained from the perspective of optimising the local distribution network (point C). Whilst this is locally optimal, the ability to access flexibility for the benefit of the whole system, in particular the ability to increase or decrease a power injection at a particular location in response to system events, may require additional network capacity.

2.2. Allocation of network responsiblities in electricity networks

There are a number of different distributions of responsibilities at transmission level across liberalised electricity markets including several models for the allocation of functions relating to the transmission network and arrangements for ensuring sufficient network capacity for the bulk transfer of power. Pollitt (2008) identifies five distinct structures relating to the combination of long term planning and ownership of the transmission system, and the operation of the bulk electricity system. At one end is a fully vertically integrated model with a single entity owning the network and operating the system as well as being responsible for generation and supply; this model was noted in Pollitt (2008), as being prevalent in Europe, although countries in the European Union have since been required to unbundle transmission ownership from generation and supply (European Parliament and Commission, 2009). At the other end is a fully unbundled model with each responsibility - long-term planning, ownership and operation – separated out. Argentina represents an example of this case where independence of the planning function (conducted, at the largest scale, by a committee of stakeholders) from the operation function carried out by an independent System Operator (SO) is required (Littlechild and Skerk, 2008).

The above structural arrangements refer only to the transmission networks, with some exceptions relating to specific very large distribution connected generators. Whilst, in theory, the same set of network responsibilities exists for distribution networks, a number of characteristics of distribution networks have meant that the opportunities for trade off at a distribution level have been minimal, and it is common across liberalised industries for single, geographically delineated distribution network entities to own the network, follow given rules on the planning of the network and carry out the generally minimal operational actions required (mainly concerned with facilitation of construction or maintenance work or recovery from fault outages). CIGRE (2014) highlights the passive planning carried out by traditionally structured distribution companies, pointing out that their methods commonly ignore distributed generation in the planning process whilst any planning for distributed generation connections tends to be reactive to a particular connection request and is based on providing sufficient network capacity to ensure secure passive – Fit and Forget – operation of the DG.

2.3. The challenges of moving towards a distributed electricity system

The growth of DG that is already underway, and the wider development of DER expected over the coming years facilitated by smart-meters, real-time monitoring, communications and control opens up the possibility of much greater active system operation potential at distribution level. As at transmission, it also opens up significantly greater opportunities for substituting operational actions for capital investment. However, the context for distribution system operation and planning is significantly different from the equivalent functions at transmission. The key differences stem from the relative size and number of DERs compared to the equivalent number of typical transmission connected resources to provide a similar capacity. A summary of the issues is presented in Table 2 and discussed in the following subsections.

2.3.1. Observability and controllability

Observability depends on measurements at key locations on the system and timely communication of measured quantities to relevant automatic controls and/or the system operator. One of the main dimensions of controllability on the transmission system has for a long

Table 2
scales and voltage levels.

Hierarchical level	Voltage level	Typical voltages	Typical scale	Typical network branch ratings	Role in supporting greater DER integration
Transmission	Extra High Voltage (EHV)	> 380 kV	National	200–3000MVA	● Greater reliance on DER for provision of system wide services.
Sub-transmission	High Voltage (HV)	110–275 kV	Region	80–300MVA	● Consideration of aggregated distribution level resources into balancing markets and ancillary services
Primary Distribution	Medium Voltage	11–80 kV	City or group of towns/ villages	1 – 50MVA	● Increased penetration of DG above fit-and-forget limit ● Aggregation of DER flexibility and reactive power capability to manage distribution network constraints
Secondary Distribution/ microgrid	Low Voltage (LV)	120 – 240 V	Neighbourhood	< 1MVA	● Aggregation of DER flexibility for bidding into national ancillary services and energy markets ● Increased penetration of DG beyond traditional voltage limitations by facilitating greater real and reactive power flexibility and management
Behind-the meter/nanogrid	Low voltage	120 – 240 V	Building	1 – 100 kVA	● Building or Home Energy Management systems can aggregate and deliver behind-the-meter response to schedules

time been the ability to modify – to increase or to decrease – the active power production of generators. Historically there has been a lack of such observability and controllability of generators and consumers connected to the distribution network. This has meant that opportunities for close-to-real time system operation functions at distribution have been minimal. Instead, in order to meet the service requirements stipulated by regulators, distribution networks are built with sufficient capacity to deal with all but the worst case combinations of demand and generation conditions with a specified level of reliability. Distribution Network companies tend to hold both the long term network planning function, executed by following well defined regulations, and the network ownership role, whilst the system operation function is largely redundant. The exception to this last point is large distribution connected generators which are large enough to usefully contribute to whole-system operational solutions. In this case, the System Operator in control of the whole system extends their responsibility to include those generators, whilst the distribution network company continues to play no real time operational role beyond facilitating outages and responding to faults.

As more generation connects to the distribution networks, this ability to operate the distribution network and connected devices in a manor analogous to transmission becomes increasingly important. Implementing this requires that Distribution Network companies to move away from their tendency to make only limited use of controls.

2.3.2. Managing people and relationships

Providing a certain capacity of generation or flexibility in the form of small to medium scale DER will require greater human and administrative resource compared with a similar capacity connected through a smaller number of large transmission connected projects. Distribution Network Operators (DNOs) to date have had relatively little experience of managing large volumes of connection offers in a short space of time or in providing the advice and support required by connection applicants that, by virtue of their small size, are likely to lack the capacity to assimilate and interpret relevant industry codes and charging arrangements. It is important that, when developing future price control agreements, both network utilities and regulators recognise the need for increased human resources for DNOs and new skills among their personnel.

2.3.3. Growing complexity

According to Rocha (2003) a complex system, rather than one that is simply complicated, is any system featuring a large number of interacting components (agents, processes, etc.) whose aggregate activity is non-linear, i.e. not derivable from the summation of the activity of individual components. A power system is non-linear but, where only thermal limits are binding, controlling a radially operated network does not appear as a complex problem, although controlling a large number of loads and/or generators to manage those constraints can be complicated. However, when voltage problems or collective behaviour starts to impact on the system as whole, complexity becomes apparent, the overall system state becomes hard to predict, and choosing the correct combination of control actions is significantly more challenging.

The number of participants in energy and ancillary service markets is greatly increased as those markets extend downwards in scale and voltage level to facilitate DER engagement. The number of participants on its own does not lead to complexity in the control problem, but can do so in combination with greater interaction between different constraints and a desire to attain a more optimal utilisation of network facilities. There is likely to be a growing need to actively manage voltage constraints and future distribution network operation may include more common use of topology adjustment, meshing or 'soft' open points, and a need to deal with multiple interacting constraints through close-to-real time power flow analysis which, in turn, depends on adequate models and system observability. In addition, the temporal resolution of markets is increasing, e.g. the Bornholm Island project which has trialled a 5 minute distribution market for power (EcoGrid, 2015) and the Australian market which dispatches plant every 5 minutes (Australian Energy Market Operator (AEMO), 2017).

Although DER connects into a distribution network and in each instance is relatively small, it has an impact on the system as a whole and on the transmission network. For example, until a number of transmission reinforcements are commissioned (National Grid, 2016a), the transmission network from Scotland to England has tended, for many years, to be export constrained. Even without reversing the flow at a particular grid supply point (the interface between distribution and transmission), new DG anywhere in Scotland will exacerbate this problem as it reduces the net demand seen by the transmission system in Scotland and the surplus of generation over demand.

The emergence of complexity raises particular issues for policy and regulation, particularly where the focus is on prescriptive rules: in a complex system, changes to one aspect of the system run a greater risk of unintended consequences. The emergence of complexity in power system operation suggests that a move towards more principle based regulation and policy making may be appropriate. Ofgem, the GB regulator, has recently committed to a move towards principle based regulation in the retail market (Ofgem, 2015c) citing the need for flexibility in the face of rapid change, for example removing a prescriptive requirement that suppliers only offer a small number of tariff options, a rule that potentially limits that ability to access and remunerate the provision of flexibility by the demand side. Similarly, in regulating levels of allowed revenue for network companies, there has been a move towards 'totex' regulation (that is, regulation of total expenditure across capital and operational costs) of energy networks (Ofgem, 2010) can be seen as an example of removing prescriptive barriers between capital and operational expenses (see Section 6.2).

2.3.4. Access to information and management of risk

The uncertainties associated with power system planning and operation give rise to risk. One general economic principle is that risk should be borne by those parties best placed to manage it. However, existing regulatory arrangements and established practices may make it difficult to achieve the best split of risk. An inappropriate distribution of risk will act as a barrier to achieving the objective of a low cost electricity system as it will lead to a higher than necessary cost-of-capital across the whole industry.

DNOs are generally the only organisations with detailed knowledge of distribution network constraints and the ability to forecast how constraints on a network and requirements for services to support distribution network operation will change over the medium to long term. Achieving an optimal development of DER and active distribution networks will require either that this information is shared more widely, in particular with parties seeking new connections to the network, or more of the risk associated with under- or over-investment in network capacity is placed on DNOs.

Ensuring a suitable split of risk is important where many DER projects are debt financed. These projects require revenue streams that are 'bankable' and there is a need to ensure that the regulatory framework delivers sufficient certainty over revenue streams to DER developers to support investment. However, this stability must be weighed against the need to respond to changing system conditions. As the penetration of DER increases, the move from large scale utility ownership to small-scale projects is likely to change the optimal risk distribution. A key objective of policy making should be to understand this changing profile, and design regulatory and market frameworks to support the optimal distribution of risk between the DER providers, large utilities and the regulated monopoly network owners and system-operators. An example of this is discussed in Section 4.1.

3. Approaches for organising a decentralised electricity system

There is a significant level of potential substitution between capital investment and operational costs in trying to achieve the objective of a minimum cost, secure and sustainable electricity system. This trade-off has long been recognised at transmission level, with decisions over the planning of the system taking into account the capital investment costs of new infrastructure and the operational costs associated with limited network capacity. However, as discussed in Section 2, the lack of active system operation at distribution level has meant that the benefits of substituting network capacity for operation costs have only recently been investigated.

As shown by the market-structures that have developed at transmission level, there are two clear ways in which the functions of the electricity system can be split between actions: a hierarchical structure in which all decisions over capital investment and operational structure are given to a single party at any one particular voltage level; and a functional structure where the functions are held by separate parties across multiple voltage-level boundaries.

3.1. Hierarchical structure

Some authors, e.g. (Hawker and Bell, 2015), have proposed that management of a large number of actors and system states associated with growth of DER and the avoidance of conflict between transmission and distribution might be effectively managed through delegation of the management of sub-systems to different parties. The key to such a hierarchical approach is the definition of where the interfaces between layers of the hierarchy lie and how the relationships between different parties interacting at that interface are managed. The key to the latter is exactly what information is exchanged and how often. Perhaps the most obvious locations for interfaces are (a) across different voltage levels and (b) across radial interfaces. The concept is illustrated in Fig. 2 in which Cells 2 and 4 either inject power into or draw power from the transmission network. However, each of those cells comprises generation and demand connected directly within them and two cells – Cells 1 and 3 – that, in turn, contain generation and demand. Provided the limits are correctly expressed at the various interfaces, the transmission system operator would know the expected net effects of Cells 2 and 4 but could also buy upward or downward adjustments from them. The operators of these cells would deliver them by adjusting generation or flexible demand within their cells or the net transfer of the cells at the lower hierarchical level. In this way, operators at each level can control overall balance and transfers to other levels without needing to know the detail within lower level, constituent cells and the potential for conflict between operators trying to control the same resources is eliminated.

Distribution and transmission represent one possible arrangement of the system into hierarchies (Table 3). At present, it is common that minimal operational data is passed between the two subsystems of

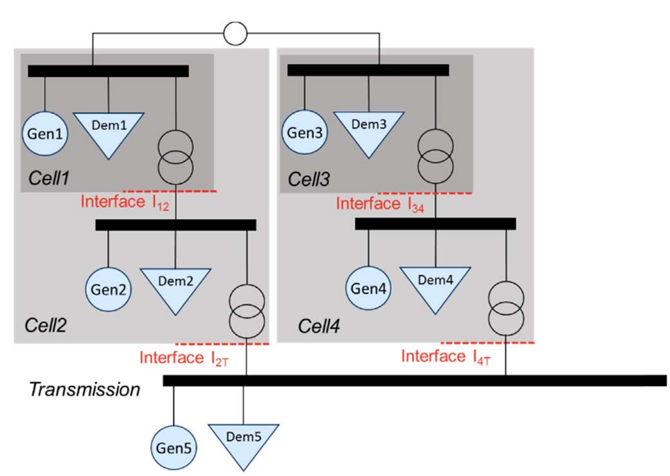

Fig. 2. network limits in a hierarchical system management approach.

Table 3
summary of the challenges to distribution network companies of integration high penetrations of DER and comparison with transmission.

Challenge	Transmission	Summary of Distribution challenge
Observability and controllability	Transmission networks are highly monitored with nearly complete real time visibility and extensive control and coordination capability exercised from a limited number of control centres.	Very little real-time monitoring and control built into distribution networks, generally limited to higher voltage levels and typically used for management of faults.
Managing people and relationships	Extensive experience of working with connected customers. However, there is a limited number of customers, each of quite high value in terms of assets and energy consumption or production requirements.	Historically, experience of dealing with a relatively small number of connection requests during the connection process. Limited experience of real-time dispatch interaction with customers from the network control centre. In future, likely to face many more requests for connection of relatively small assets.
Growing Complexity	Use of sophisticated analysis tools developed over decades, informed by extensive system monitoring. Experience has led to well-established procedures and heuristics. However, a number of system incidents worldwide, e.g. whole system blackouts, reveal the limits of procedures, models and tools.	Increasing DER and control options means the operation of distribution networks is likely to become increasingly *complicated* due to the large number of DER and *complex* due to non-linear and integer interactions.
Access to information and management of risk	Connection arrangements such as payment for curtailed energy provide some sharing of risk between the network company and generators / demand connections. Transmission connected resources generally backed by entities large enough to support significant resources for analysing and managing risk.	Historically, network operators exposed to little risk. Connected parties face risk of disconnection or, in newer, 'active network management' schemes, curtailment of output.

transmission and distribution. The move to an active DSO in order to facilitate the contribution of DER to system operation would increase that required data transfer. Further hierarchical division may be desirable, for example at a very local 'micro-grid' level.

3.2. Functional structure

An alternative to a hierarchical approach is where responsibility is split by function and any one of them may be exercised by the same party across different voltage levels. In broad terms, the functions relevant to planning and operation of power networks include:

- provide connection and use-of-system contracts to connectees;
- specify the need for new network infrastructure;
- design, build and maintain physical connections to connectees;
- design, build and maintain network infrastructure;
- carry out switching on the network to enable safe working, e.g. for repair, maintenance or construction;
- approve planned outages and dispatch system control settings such as voltage targets, nodal power injections and network configurations for power flow and fault level management.

Fig. 3 depicts the delineation of network functions in GB at the time of writing. Of particular note is that larger distributed generators can provide flexibility to the SO at transmission level such that the SO can change their production of power. Therefore, the operation role is held by the System Operator across different voltage levels, whilst the network ownership role is held elsewhere. However, as is discussed in Section 5, some blurring of responsibilities and conflicts can happen where a distribution connection is actively managed meaning that the DNO has some control over DG output. Some blurring also exists in respect of large generator connections to distribution networks where the generator needs to obtain transmission use of system rights.

The functional separation becomes particularly important where the building, ownership and maintenance of new transmission links have been competitively tendered, as is the case in Argentina, for example (Littlechild and Skerk, 2008). In this case it becomes important that the need case for particular network infrastructure is defined independently from the ownership of those lines. This can be contrasted with the case in much of Europe where the SO and TO are integrated within one organisation. As is discussed in Section 5, future arrangements may involve the extension to lower voltage levels of all of the transmission system operator's system operation activities or the enlargement of the DNO activities to include dispatch of all controls for system operation.

4. Concepts for coordinating Distributed Energy Resources

Several concepts have been developed over the past few years, or are in the process of emerging, which have the potential to aid the accommodation of DER within distribution networks and to begin to advance the potential for system operation actions at the distribution level. Table 4 summarises five such concepts, each of which is further discussed below.

4.1. Active Network Management (ANM)

One solution to the problem of limited network capacity and a high demand for distribution connections for generators has been the growth of 'Active Network Management'. This adds minimal monitoring and control equipment to new connections, combined with a centralised controller but allows the continuation of unconstrained operation for previous connections. A number of DNOs in GB have implemented some form of ANM scheme for the avoidance of thermal overloads of key network branches, e.g. (Currie et al., 2011; UK Power Networks, 2015). Because it is a new approach for these DNOs, they have tended to make use of innovation funding to help pay for it, for example through innovation funding allowed by the regulator (Ofgem, 2017a). According to Frame et al. (2016), ANM is now regarded as a credible 'business as usual' option to offer to DER connection applicants.

From a system perspective, ANM facilitates curtailment and therefore allows the DNO to move from the fit-and-forget position in Fig. 1 towards the optimal combination of curtailment and reinforcement

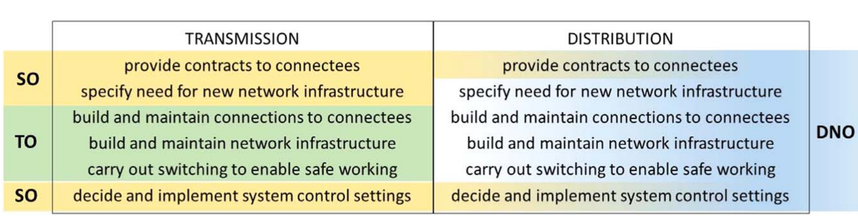

Fig. 3. Delineation of functional roles in a power system between SO, TO and DNO under the current regulatory arrangements in Britain.

Table 4
Developing concepts for coordinating DER.

Concept	Summary
Active Network Management	The rule-based automated management of distributed generation where additional generation capacity is connected and output is curtailed from time to time to keep power flows within allowed levels.
Virtual Power Plants and Aggregators	The pooling or aggregation of output and demand from multiple DER to sell into energy or ancillary service markets
Peer to peer electricity trading	Transacting electrical energy directly from generator to a consumer without the intermediary of a supply company.
Distribution System Operation	An entity which carries out long-term planning and operation of the electricity networks, and actively implements network control actions, e.g. to dispatch DER resources, on a regular basis.
Highly Distributed Locational Pricing	The use of location- and time-specific energy prices representing, to some degree, the short run cost of serving demand at a particular time and location. For example, prices will be low where excess low-marginal cost generation is available.

costs. The benefits of ANM to connection applicants are (i) reduction of the cost of the connection and (ii) reduction of delays to connections that may arise due to the need for planning approval for a conventional network reinforcement and its construction. However, experiences of some DG operators suggest some problems, the most important of which is that levels of curtailment can be greater than they were led to expect by the DNO when they accepted the ANM-based connection offer, e.g. (Local Energy Challenge Fund, 2014).

ANM-related connection offers to date have typically been financially as well as physically 'non-firm' in that the connectee receives no compensation for curtailment. The business case for a generation development then depends on how much energy can be physically exported and sold compared to the costs of the development, not how much energy was available. Greater than expected levels of curtailment may mean that the costs cannot be recovered. Under such circumstances, the connectee may be well advised not to depend on the DNO's forecasts of curtailment. However, few connectees have access to information on the network's configuration and limits or the demand profile where their network constraint concerns a net export. Furthermore, both generation and demand can be quite different from one year to the next, e.g. due to variations in weather or closure of a local energy consumer's premises.

Current practice regarding ANM highlights the issue of risk sharing discussed in the previous section – existing ANM arrangements place all the risk of curtailment costs on the DER developer, who may be unable to either quantify or influence that risk themselves, and not on the DNO. Although it might be argued that the DNO's regulatory settlement and cost of capital are predicated on low or no risk, there would also appear, in conventional rate-of-return regulation of income for network owners that treat opex and capex separately, to be no strong incentive to innovate to find cost-effective solutions to problems in the overall best interests of energy users. A more balanced share of risk, where the DNO takes more than under present arrangements and the DER less, could lead to a small increase in the cost of capital for DNOs but a larger drop in the risk premium paid by DER developers. It should be self-evident that the DNO has better access to information to enable the management of the risks associated with uncertain power transfers than the operator of a connected DER. One way in which risk might be shared between DNO and DER developer would be by the DNO being obliged, in effect, to buy back the DER's network access rights when curtailment is required with the price of such an action perhaps being regulated, set as part of a connection agreement or subject to a market. This would require careful setting of some additional DNO income such that they are incentivised to take good operational decisions but do not receive a windfall. The 'totex' arrangements now being used in price control settlements promise to provide a framework within which to do that (See Section 6.2).

The introduction of curtailment and non-firm access to the networks introduces a number of options for the sharing of network access between generators. Maximising the capacity of DG connected to a particular network within the economic constraints of each DG project requires ensuring that no one generator receives excessive curtailment. A number of options exist for sharing limited network capacity, e.g. those discussed in (Baringa, 2012); however, the one chosen by most GB schemes – Last In First Out (LIFO) – ensures that curtailment is increasingly concentrated towards specific generators, namely those connecting later, rather than aiming for an economically efficient share (Hawker et al., 2013). The advantage of LIFO is that, as other DG connects, it avoids increasing the curtailment of the first party relative to what the developer expected when they accepted a connection offer. However, it fails to test the value that each party attaches to network access at any particular time. In other words, e.g. to avoid burning fuel, the first party may be willing to give up, temporarily and for a short period of time, its network access or to be paid some nominal amount for it.

The ANM schemes' roll out to-date represents a form of hierarchical arrangement of responsibilities. The DNO is expanding its responsibilities from the planning and ownership of the distribution network to the real time-control of the DER devices connected to it. ANM falls short of full system operation as it delivers real-time control through a set of automated systems. However, its deployment represents a first step in overcoming the barriers discussed in Section 2.3.

4.2. Virtual power plants and aggregators

A Virtual Power Plant (VPP) comprises the aggregated output of a number of distributed resources at such a scale that justifies inclusion in wholesale markets for energy and ancillary services. Instead of interacting with each individual party comprising a VPP, a buyer of energy or ancillary services from the VPP needs to work with just one party; the operator of the VPP resolves which VPP constituent provides what.

The relationships inherent in a VPP exist on two levels: one between DER owners and the VPP operator and the other between either the VPP operator and retailers (in the case of the sale of energy) or between the VPP operator and the system operator (in the case of ancillary services). This set of relationships does not normally include the DNO, and dispatch either of the VPP as a whole, or of individual components of a VPP does not, in general, pay any attention to location and network congestion. This has led some to define 'commercial' VPPs separately from 'technical' VPPs that are somehow inter-related though in often ill-defined ways (FENIX, 2008; Pundjianto et al., 2007).

If interaction with the DNO is neglected, VPPs cannot help achieve the goal of an optimally planned and operated distribution network. Whilst they can increase the pool of providers for ancillary services and increase the reach of the wholesale energy market thus facilitating more efficient market operation, they run the risk of doing so in a way that a DNO feels can only be managed by 'fit and forget'.

VPPs and aggregators represent a functional distribution of responsibilities with the DNO retaining responsibility for network ownership, but the VPP taking responsibility for dispatch. The development of VPPs and aggregators under current distribution network regulation is unlikely to realise the inherent benefits of DER flexibility. For example, planning regulations will continue to size the network for the full simultaneous output of all generation resources whilst assuming the simultaneous minimum draw of power by demand resources. For this hierarchical structure to realise the inherent benefits there needs to be a clear method of communicating network capacities from the network owner to the VPP and possibly information on the dispatch from the VPP to the network owner.

4.3. Peer-to-peer electricity trading

Inspired by other sectors such as retail, temporary accommodation and taxis, e.g. eBay, AirBnB, and Uber respectively, there has been speculation about the facilitation of 'peer-to-peer' trading of electricity. It has been argued that this would be especially beneficial for DER where, for example, a match might be made between the owner of a rooftop solar PV panel who has surplus power available in the middle of the day and an electricity user looking for the cheapest energy at that moment and, by matching generation and demand, help to reduce the need for network capacity.

In recent years a number of business models have been trialled aiming to encourage aspects of peer-to-peer trading of electricity. In Britain, a commercial trial of one trading platform, Piclo, was conducted in 2015/6 (Open Utility, 2016) which allowed consumers to buy electricity from particular producers brokered through a retail (supply) company. In the Netherlands, Vanderbron allows consumers to choose to buy power from individual generators (Vanderbron, 2017) via a webpage in a format similar to those used in other sectors which, for example, highlights the producer's ethical, environmental and social credentials. In Germany, the sonnenCommunity (Sonnen, 2017) project allows members to directly trade with each other for a monthly platform fee in close to real time.

In a fully realised version of peer-to-peer trading, individual generators that failed to sell their electricity over the peer-to-peer platform would presumably be unable to generate without facing imbalance charges, unless they had additional arrangements such as a Power Purchase Agreement (PPA) for excess production. Similarly, a consumer who had failed to buy sufficient power would face imbalance charges. Such arrangements would effectively bring incentives and risks to DER similar to those of wholesale balancing mechanism cash-out prices.

In its current form the concept of peer-to-peer trading on its own does not deal with many of the technical challenges that increased DER penetration will bring. In particular, in its basic form, it does not consider network constraints. It would seem to rely on a traditional fit-and-forget network arrangement to ensure that trades enacted by users can be physically accommodated. As with VPPs, this is because peer-to-peer trading represents a functional delineation of responsibilities, and in its simplest form makes no allowance for sharing of information and responsibilities between parties.

To adjust a peer-to-peer model, it is important that regulation and policies allow for a more actively managed distribution network. One option is for DNOs, or some other competent party using the DNO's data, to be allowed to publish current and forecast network constraints close to real time in a form that a peer-to-peer platform can assess and that will effectively prohibit physically infeasible transactions. A second option is that some party is nominated to carry out post-transaction congestion management in a similar way to that which is conducted at transmission level although such an arrangement would undermine the peer-to-peer rationale as consumers would then not be guaranteed which generator was matching their demand.

4.4. Distribution system operator

The lack of information about distribution network constraints incorporated into VPP and peer-to-peer trading, at least in their simplest manifestations, highlights the limitation that optimal distribution network planning and operation faces if parties responsible for respecting limits, e.g. distribution companies, are not involved in the process.

At the time of writing, there is a discussion in many countries about the need for distribution companies to evolve into Distribution System Operator (Smart Net, 2016; EDSO, 2015; Ofgem, 2015a; SP Energy Networks, 2016). A useful distinction is made in Britain between a Distribution Network Operator – DNO – and a Distribution System Operator – DSO – with the latter taking a more active role in operating the system.[1] This involves, for example, actively monitoring and managing generation outputs, reconfiguring the network and adjusting voltage targets on the distribution networks more frequently than has been the case in the past. Such practice would go beyond the simple pre-determined control logic employed in ANM schemes to date, and allow more complex, real time and interactive management techniques. Compared to now, this requires monitoring and active management of a vastly increased number variables for the system as a whole (The IET, 2013). However, the policy steps towards more active distribution have, so far, been few.

As with ANM, the move towards full Distribution System Operation represents a move towards a more hierarchical arrangement of the power system. However, the extent to which that occurs depends on the relationship between the DSO and the System Operator at transmission level and is discussed further in Section 5.

4.5. Highly distributed locational pricing

An example of a potentially radical reform of an electricity market is New York State's 'Reforming Energy Vision' (REV) programme (New York State Energy Planning Board, 2015). One notable feature in this context is the greater consideration of the locational value of DER in trading arrangements (NYS SmartGrid Consortium, 2015; Tabors et al., 2016). This greater focus on locational pricing for DER is examined in detail in the recent Utility of the Future Study (MIT, 2016) which discusses the potential role of Locational Marginal Prices (LMPs) in creating locational signals for DER. The report highlights that whilst LMPs may represent the "perfect marginal short term energy price" (MIT, 2016, pg 104) they do not provide a suitable long term investment signal due to the lack of information that users have regarding their impact on future network upgrades, and have to date not been used in distribution pricing. Calculating distribution LMPs would require the development of a suitably powerful software platform capable of managing hundreds of thousands of data points and computing and communicating locational marginal prices at regular intervals. The linearized power flow equations used to calculate LMPs at transmission level are not appropriate for voltage constrained low voltage distribution networks where the effect of resistance and voltage variations would require a non-linear optimisation. Moreover, network reconfigurations – standard tools for distribution operators to manage power flows – are difficult to represent in conventional optimisations used for calculating LMPs.

The long-term success of highly distributed locational pricing in bringing about an optimal or near optimal set of location decisions by new network users, time of use decisions by all network users and investment decisions by network owners will depend on price signals being correctly interpreted. For many small actors, this will be highly challenging and is likely to require third parties being contracted to do it for them or on suitable building or home energy management systems. Although it might be decided not to implement a highly distributed market using distribution LMPs, the computation of LMPs might still inform distribution network pricing and investment studies.

5. Coordinating distribution and transmission

The discussion above has focused mainly on the potential for integrating DER within the distribution network itself. If this question is considered in isolation the resultant split between capital and

[1] Note that the term DSO is commonly used in many countries to refer to any distribution network company and the distinction between DNO and DSO is not made explicit.

operational costs incurred by the distribution network owner may be internally efficient but may inadvertently limit the ability of DER to contribute to system wide and transmission related issues. The potential for conflict between the actions of the transmission System Operator and a DNO is also becoming increasingly apparent. For example, a DNO may have given an ANM-related connection to a DG that also participates in the transmission system balancing mechanism. There is the risk that if that DG reduces its output in response to a bid acceptance by the SO, the automated ANM scheme will respond by allowing increased output at other actively managed generators. A similar potential conflict arises in respect of DG with a contract to provide the transmission system operator with short-term reserve services where a short-notice increase in generation is required from time to time. This requires headroom on both the generator providing the reserve and on the distribution network between the generator and the interface between transmission and distribution. Under existing ANM schemes, there will be occasions where the reserve cannot be delivered due to distribution constraints (National Grid, 2016c). New arrangements for coordination between transmission and distribution are required and will necessitate changes to regulatory and commercial frameworks that must be driven by policy makers.

A number of reports have investigated the options to relieve this lack of coordination, for example SmartNet, 2016 and ENTSO-E, 2015 in Europe and DeMartini and Kristov (2015) in California. These discussions differentiate between a functional arrangement with the incumbent SO at transmission level extending its system operation functionality to cover a much wider collection of resources connected at the distribution level while the DNO retains ownership; and a more hierarchical arrangement where the DNO takes full responsibility for the operation and close-to-real time dispatch of DER connected to its network and shares the appropriate information with the SO at transmission level. As an example, the models proposed by DeMartini and Kristov can be summarised as follows:

- **Total TSO** in which a system operator acting at transmission level (TSO) models and optimizes the whole system, with visibility of distribution grid conditions and all DER above a low size threshold. The DNO has minimal new functions, its operational role being limited primarily to ensuring safety and the reliability of assets.
- **Minimal DSO** in which a TSO optimizes the whole system, including the dispatch of a large number of individual DER resources but without access to monitoring of distribution network conditions and constraints. The DNO must be capable of analysing the TSO's dispatch and adjusting it to stay within its own network's limits.
- **Market DSO** which maximizes the DNO role in operational coordination so that it becomes, in the terminology used in GB and discussed above, a full DSO. This minimizes complexity for the TSO. Two variants presented distinguish between a system where the TSO sees a small number of aggregated DER resources at the transmission-distribution interface and a system where only one aggregated resource is presented.

DeMartini and Kristov note that whilst the Total TSO model is interesting for comparison, they believe it to be impractical due primarily to operational complexity. The simplest model is seen as the Market DSO model. This is the one that most closely approximates a fully hierarchical organisation of the power system.

The Total TSO model represents a functional arrangement where the TSO in this case would take responsibility for dispatch across all voltage levels whilst, in parallel, the network owners would design, build and maintain the network. At transmission level, a clear example of functional delineation is seen in the use of Independent System Operators (ISOs) where the SO has no ownership of the network itself.

6. Discussion: policy, regulation and market design issues

The growth of DER and the potential for it to add up to a very substantial resource that can not only add to energy market competition and choice but also contribute to (or, if poorly integrated, threaten) system operation suggests that the choices made by regulators and policy makers in determining the precise form of electricity trading arrangements, system operation and network planning and investment should be carefully reviewed.

6.1. Regulation and market design

The regulatory regime plays an important role in defining the commercial framework within which companies operate and compete and which, in turn, helps to signal correct investment and operation decisions by network utilities. Specific regulatory decisions can have a significant impact on the likelihood of services from particular classes of assets being offered. Factors can include the time between contracts being awarded and their delivery, and the design of standardised products used to procure services. As an example, Order 755 of the Federal Energy Regulatory Commission in the US (FERC, 2011) represents an instance of the second point: a perceived failure of US systems to acknowledge the greater value of frequency regulation provided by fast ramping resources. The FERC order requires System Operators to ensure compensation reflects the actual services provided as well as payments related to performance.

A second area where regulation can impede the achievement of the lowest cost solution is through the introduction of additional regulatory uncertainty. A number of reviews have identified the fact that private developers will regard regulatory uncertainty to be so high that, under 'real options' analysis, investors will delay investments (Ishii and Yan, 2004; Warren, 2014).

The complexity of a power system and the importance of respecting physical system limits seem to require some degree of coordination, e.g. through centralised dispatch decision making. The main commercial framework decisions for facilitating system operation across multiple hierarchical system levels that should be made by policy makers and regulators may be summarised as follows:

- **Time horizon,** i.e. the moment before real-time at which centralised arrangements take effect. The main trade-off here is between (a) giving market participants the opportunity to make their own choices as close to real-time as possible, so maximising certainty about, for example, demand and the availability of generation; and (b) the need for the system operator to have sufficient notice of the need to take action to resolve system-wide or local imbalances and the opportunity to optimise the time scheduling of generating plant outputs given their physical limits. For markets covering distribution levels, market designers will need consider which physical constraints are placed on their markets and how new market participants will engage with the market.
- **Length of each trading period,** i.e. temporal granularity. Here the trade-off is between number of transactions, volume of data and potential price volatility, and the need for ancillary services 'outside' the energy market to manage the dynamics and stability of the system. In principle, short trading periods can reveal, through system prices, the need for quite rapid increases or decreases in production or consumption and therefore reduce the need for separate ancillary service arrangements. Very short trading periods – such as 5 minutes markets – combined with a large number of DER providers could be limited by the ability of communication, control and market-clearing arrangements to process and dispatch the devices. A hierarchical arrangement where trades will need to

percolate up across several layers, and dispatch percolate down, may place new constraints on the minimum feasible trading period.

- **Spatial granularity,** i.e. nodal versus zonal versus system pricing. Here, system or zonal pricing ignores within zone congestion, thus failing to clearly incentivise operation of plant in import constrained areas and disincentivise it in export constrained areas; on the other hand, nodal pricing can make it easier for a party at an import constrained location to exercise market power and prices can be highly volatile and less predictable. The reduction in predictability may have a disproportionately large impact on small DER projects where the bankability of revenue streams is an important consideration, and as the level at which nodal pricing is applied decreases, opportunities for the exercise of market-power will increase.
- **Length of contract** to which providers can gain access. Short contracts allow the market to adjust quickly to new providers or changes in requirements; however, in such a case, medium term risks are carried by providers who are not guaranteed a revenue stream in future years. Longer contracts give certainty to service providers with known costs. An example of this trade-off is evident in the GB Enhanced Frequency Response arrangements where four year contracts have been awarded for the provision of frequency response on time scales of less than 1 s. Relative to other ancillary service contracts in GB, 4 years is a long time, intended to provide sufficient certainty to battery storage developers although the SO notes that “We recognise that four years is not very long when investing in new assets; however, National Grid [the SO] is a regulated business and therefore sanctioning contracts longer than two years because of the funding arrangement together with the forecasted market conditions involves us taking on an unacceptable level of risk” (National Grid, 2016b). The impact on DER will need to consider how the contract length affects the perceived risk of investing in DER, and therefore the cost of capital, as well as how that capital is funded.

Policy makers need to reflect on what an ‘unacceptable level of risk’ for a system operator is in the context of the whole electricity system where that risk, if it inappropriately falls on smaller DER providers, has the potential to lead to sub-optimal choices. Consideration of the size of potential market participants can play a part in a market's design. Each extra participant in a particular market aids liquidity and competitiveness but also adds to the communication overhead and total transaction cost. Smaller parties are less likely to have the critical mass needed to invest in communication and control facilities and to be able to engage with and make sense of what is often a large and complex set of market codes and rules or to have the expertise to make rational interpretations of market signals.

Although theoretical efficiency may come from higher spatial and temporal granularity and shorter length contracts, transaction costs and the need for investors and service providers to have some degree of certainty must also be taken into account if investors’ costs of capital are not to be excessive.

6.2. Incentives for network utilities

A minimum whole network cost depends on an appropriate balance between asset-based interventions and operational measures such as redispatch of generation, with the two types of action substituting each other where appropriate. Under some regulatory structures, network owners have strong incentives to increase the size of their asset base, for example rate of return type of regulation common in US markets and the aspects of British regulation based on Regulated Asset Values (RAV) (Newbery, 1997; Strbac et al., 2013). Under arrangements such as those that prevailed in Britain prior to 2013, income is set by the regulator at each price review for the coming price control period. It is set such that it covers what are regarded as reasonable operating costs, the cost of new capital investment and the recovery of previously incurred capital expenditure.

As part of a network owner's submission of information for a forthcoming price control, there was arguably an incentive to ‘talk up’ future capital expenditure requirements such that the network owner's revenues in the forthcoming price control period are maximised. However, once prices are determined for a particular price control period, i.e. revenues are set, there is arguably an incentive to *avoid* capital expenditure. This reduces cost in the short term, in particular the cost of borrowing, albeit at the expense of continued future income in subsequent price control periods linked to the size of the asset base. Moreover, any assets deemed not to have been required are subject to being regarded as stranded and struck from the asset base thus attracting no income.

Most network licensees in Britain are now part of companies that have much wider interests than just ownership of regulated power networks in Britain. Any potential investment requires the raising of funds and will be compared with alternative uses of funds that are available to the parent company. Often, investments other than in regulated power network assets in Britain will appear more attractive.

Since 2013 for transmission networks and 2015 for distribution networks, the GB regulator has used a new form of regulation: RIIO (Revenue = Incentives + Innovation + Outputs) (Ofgem, 2010). Both the network owners’ capital and operational income streams are subject to adjustment relative to, for example, volumes of new generation or demand connections. Thus, if capex is undertaken in anticipation of, for example, demand growth that does not take place, income will be reduced and, if the income adjustment is set correctly, at least part of the cost of the new assets will not be recovered.

Also, under RIIO, DNOs’ future expenditure requirements are not assessed in terms of separate categories of capex and opex but in terms of total expenditure, i.e. ‘totex’. An income stream is set in respect of totex. In principle, this allows – indeed, incentivises – a DNO to choose a cheaper operational solution in favour of a more expensive, asset-based one and to realise a surplus (or reduced deficit) relative to their income and counteracts the potential for rate-of-return regulation to incentivise over-investment. However, in Britain, an incentive on a single network licensee to choose correctly between asset-based and operational measures has not been applied at transmission level where, instead, as part of an initiative known as ‘Integrated Transmission Planning and Regulation’ (ITPR), an increasing separation between network ownership and system operation is being driven (Ofgem, 2015b).

6.3. Delivering a transition

Buyers of services need to have trust in providers. Where third parties are involved, the end providers need to have confidence that they will receive a fair share of the benefits. A particular market with much scope for development but considerable uncertainty about how quickly it will happen is the provision of flexibility on the demand side. As noted by policy makers in (BEIS and Ofgem, 2016), it will depend not only on suitable tariffs and time of use metering but also on understanding.

The efficient accommodation of DER seems to require innovation in respect of the practice of distribution network management. Policy has an important role in encouraging effective and successful innovation. In Britain, the regulator has encouraged innovation by making certain funding sources available. Much of the expenditure from these has been focussed on equipment that was, to date, unfamiliar to DNOs in Britain and knowledge has been gained on commissioning and operational performance. The growth of complexity in electricity systems arising from penetration of DER requires a broader scope for innovation that expands it from trialling technologies in isolation to the coordination, integration and optimal operation of multiple technologies as well as commercial and regulatory decision making in the face of a wider range of choices. Policy makers must also ensure that the success criteria of innovation projects are appropriate. Frame et al. 2016, show evidence that, in GB, success has tended to be judged in terms of whether or not an innovation has been adopted as part of 'business as usual'. More useful judgements include whether a project provides useful evidence to answer the question: should this innovation be further developed or not; and whether the innovation is now ready to be considered option to address needs as they emerge?

Section 2.3.1 highlighted the challenges of limited controllability and observability on the distribution system. The associated monitoring and communication equipment incurs a cost but it can be delivered in stages provided the equipment is sufficiently inter-operable and earlier installations are maintainable and use protocols that do not become obsolete so quickly that replacement and early asset write-off is required. When considering what kind of model of future network planning and operation to adopt, information and communication technology (ICT) risks should be considered.

7. Conclusion and policy implications

We conclude by noting that arrangements for energy trading, system operation and network investment be should be based on a common set of principles that apply across voltage levels even if detailed implementations differ between them. The following subsections identify these key principles, together with their policy implications.

7.1. The overall cost of the system is minimised within environmental, reliability and quality of supply constraints that accurately represent societal and individual preferences

Policy should focus on principles that support this objective, rather than on prescriptive rules. For example, in Britain, the system-wide impacts on energy-balance and transmission congestion do not depend on whether a generator is distribution or transmission connected. However, use of system charging arrangements in place today give distributed generation in GB a significant advantage over similarly sized transmission connected generators. This is in the process of being changed through a further prescriptive rule applying to distributed generators (Ofgem, 2017b). However application of a higher-level principle that any actor (generator, demand or storage) pays dependent on their contribution to peak-flows would make arrangements more robust against changing circumstances, the emergence of new technical solutions and the ability to access services from a more diverse range of suppliers.

7.2. The system can be safely operated in accordance with relevant physical limits

The requirement for all parties in the electricity system to operate safely will remain paramount. However, policy makers and regulators need to consider who is responsible for monitoring and sharing information on the physical limits and existing state of the electricity system at all levels. The present arrangements at transmission level, where network owners and power station operators provide information to a central System Operator, may need to be replicated at distribution level. However, policy makers will need to decide which party should be in receipt of that information and charged with taking action based on it. For example, it may involve extending the current System Operator's responsibilities downwards, facilitating local market and system operators such as 'distribution system operators' that interact with each other and a transmission level operator, or a hybrid.

7.3. Access to the electricity system is fairly and efficiently facilitated for users of the system at all scales and voltage levels

This represents a key tenet of liberalised electricity systems, and will remain true despite the significant technical changes to system operation and planning. However, without changes to policy and regulation there is a danger that the system is unable to achieve it. For example, where DER are unable to receive revenue for the value they provide in offsetting network upgrades, or are not incentivised to dispatch efficiently once connected, this principle will not be achieved. Market platforms such as those being developed within the New York REV project where flexibility providers can bid to provide 'non-wires' solutions to network constraints (i.e. operational rather than capital investment based solutions) allow this (NYS SmartGrid Consortium, 2015).

7.4. Risk and uncertainty is held and managed by those best able to manage it

The existing model of very low risk regulated monopolies is likely to lead to an inefficient share of risk between parties in an energy system with high DER penetration. Individually, even relatively small quantities of risk can increase their cost-of-capital, raising overall system costs. A future objective of policy development related to minimising costs should be the facilitation of the optimal spread of risk across the types of parties engaged in the system. This will be particularly relevant to small debt-financed DER developers looking for firm revenue streams that can be used to leverage loans.

7.5. Innovation is encouraged

Policy makers need to ensure that the design of innovation funding is able to deliver the types of innovation required by the more complex systems that are likely to develop with high DER penetrations. At present, innovation funding is often directed at the demonstration or development of particular technologies in isolation, with success criteria often implicitly biased towards successfully proving the immediate usefulness of a technology. Instead, in a complex system, a key focus of innovation funding needs to be the coordination and interaction of multiple technologies. Success should be judged on the quality of evidence collected and whether that provides sufficient information for making informed decisions on the future of a particular innovation; projects which successfully show that a particular innovation should *not* be taken forward are equally important.

7.6. The complexity of market arrangements and incentives is managed such that, while signals are as reflective of whole electricity system costs as possible, active participation in different markets is encouraged

By basing regulation on principles and allowing market and system operators at all levels to design service products that suit their situation, it should be possible for policy makers to incentivise DER that can provide multiple services. More prescriptive regulation can arbitrarily limit the number of services that can be 'stacked' by a DER provider. Similarly, the existing functional division of network provision and services and the increasingly arbitrary divide between transmission and distribution act as barriers to achieving the most value from DER. For example, storage can provide services that are valuable to the system operator at times of low demand (for example very fast frequency response to compensate for low levels of inertia) and other services that are valuable at times of high demand (for example capacity and reserve) (EPRI, 2014). Ancillary service products that do not allow flexibility to provide different services at different times will arbitrarily limit participation and are likely to slow the development of particular DER.

7.7. Summary

This paper has discussed changes to the nature of power systems and has argued that a least cost power system that meets decarbonisation targets and energy users' expectations in terms of reliability of supply requires a re-thinking of roles and responsibilities in respect of the power network, in particular the way distribution networks are managed. These changes require a significant alteration to the policies that guide and influence electricity utilities' actions. The most important policy interventions are in the design of the markets that operate to procure services competitively from the pool of possible providers, and the regulatory systems that incentivise and direct the monopoly elements of the system. In these areas policy makers need to consider where and when hierarchical and functional delineations of responsibilities are best suited, and how best to overcome the increasingly arbitrary divide between transmission and distribution. We suggest that a greater role for hierarchical delineation will allow network operators to choose between asset based interventions and operational measures such as curtailment; however, this should not be a blanket decision with functional delineation likely to be more suitable for other aspects. When designing policy, markets and regulation, policy makers must be careful not to impose arbitrary rules, and we have argued that principle based approaches are likely to be more appropriate for a highly distributed electricity system than tight prescription. The management of risk and innovation have also been identified as important challenges for policy makers.

Acknowledgements

This work has been carried out as part of the research programmes of the UK Energy Research Centre (grant EP/L024756/1, www.ukerc.ac.uk/) and ClimateXChange (Energy System Modelling Grant, 2014, www.climatexchange.org.uk/).

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