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

Keith Bell, Simon Gill*

Department of Electronic and Electrical Engineering, University of Strathclyde, Royal College Building, 204 George Street, Glasgow G1 1XW, United Kingdom

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*

---

* Corresponding author.
E-mail addresses: keith.bell@strath.ac.uk (K. Bell), simon.gill@strath.ac.uk (S. Gill).

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
0301-4215/

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