Electric Power Systems Research 141 (2016) 63–72

Contents lists available at ScienceDirect

Electric Power Systems Research

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

Regulatory capital and social trade-offs in planning of smart distribution networks with application to demand response solutions

Eduardo A. Martínez Ceseña [a,*], Victoria Turnham [b], Pierluigi Mancarella [a]

[a] School of Electrical & Electronic Engineering, The University of Manchester, Manchester M13 9PL, UK
[b] Electricity North West Limited, Warrington WA3 6XG, UK

ARTICLE INFO

Article history:
Received 23 December 2015
Received in revised form 27 June 2016
Accepted 1 July 2016

Keywords:
Demand response
Investment planning
Multi-criteria assessment
Smart distribution networks
Smart grid

ABSTRACT

Under the current UK regulatory framework for electricity distribution networks, asset upgrades are planned with the objectives of minimising both capital costs (and thus customer fees) and social costs such as those associated with carbon emissions and customer interruptions. This approach naturally results in economic trade-offs as network solutions meant to reduce social costs typically increase (sometimes significantly) capital costs, and vice versa. This can become an issue in a smart grid context where new operational solutions such as Demand Response (DR) may emerge. More specifically, even though there is a general belief that smart solutions will only provide benefits due to their potential to displace investments in costly assets (e.g., lines and substations), they may also introduce trade-offs associated with increased operational expenditure, power losses and emissions compared with networks with upgraded assets. On the other hand, the flexibility inherent in smart solutions could be used to balance the different types of costs, leading to attractive cost trade-offs if properly modelled, quantified and regulated. However, given the fundamental "non-asset" nature of DR, properly quantifying the resulting trade-offs so as to perform a like-for-like comparison with traditional planning strategies is a grand challenge. In this light, this article proposes a methodology to explicitly model and quantify capital and social cost trade-offs in distribution network planning, which can be incorporated into the existing regulatory framework. The results, based on real UK distribution networks, show that our proposed methodology can be used to explicitly model and regulate cost trade-offs. By doing so, it is possible to encourage more efficient levels of capital expenditure and social benefits by deploying the right mix of traditional asset-based and smart DR-based solutions.

1. Introduction

Since the privatisation of the UK's electricity sector began in 1990, the regulatory framework of distribution networks has undergone several revisions based on the constantly changing objectives and conditions of the nation and the electricity sector [1–3]. Early versions of the distribution regulation focused on reducing economic costs for customers by encouraging Distribution Network Operators (DNOs[1]) to make cost-effective investments and gradually reduce their capital expenditure and customer charges. Later, emerging environmental concerns and increasing dependence on electricity emphasised the importance of different social[2] costs associated with the distribution network such as electricity supply reliability, carbon emissions and electrical power losses.[3]

This change in regulation is introducing trade-offs between capital and social costs, as additional capital expenditure may be necessary to design distribution networks that facilitate the mitigation of social costs. Furthermore, in the last few years, it has been recognised that mitigating social cost while maintaining relatively low capital expenditure at the distribution level is a grand challenge under business-as-usual practices, particularly in the light of an increased penetration of renewable energies distributed

* Corresponding author. Tel.: +44 0 161 306 4807.
E-mail address: Eduardo.MartinezCesena@Manchester.ac.uk (E.A. Martínez Ceseña).

[1] DNOs own, operate and upgrade the electricity distribution networks.

[2] Social costs are defined based on the regulation in place (Ofgem, 2013a) and may also include risk of injury and environmental impacts of using particular types of oils for the transformers, which are not considered in this work as they are not relevant to the DR solutions considered in this work.

[3] It is worth noting that power losses have well-defined capital impacts and, thus, may be considered capital costs under the regulatory framework of other countries.

http://dx.doi.org/10.1016/j.epsr.2016.07.001
0378-7796/

throughout the distribution network, the electrification of heating [4], and so forth. Accordingly, the latest versions of the regulatory framework of the electricity industry have been aiming at encouraging the development of new and smart solutions that typically rely on the active participation of customers in the management of the system via Demand Response (DR) as a means to mitigate both social and capital costs [5,6].

The new "Revenue = Incentives + Innovation + Outputs" (RIIO) network regulation model (from April 2015 to March 2023) [7,8] aims at regulating the revenues accrued by DNOs to incentivise the development of innovative and smart solutions, which may facilitate meeting desirable outputs (e.g., target levels of capital expenditure and social costs mitigation). Based on this principle, the UK regulator, namely the Office of gas and electricity markets (Ofgem), is introducing a Cost Benefit Analysis (CBA) framework (hereafter named "Ofgem's CBA") to plan and assess distribution network upgrades as a part of the first RIIO regulation for electricity distribution (RIIO – ED1) [9–11].

Ofgem's CBA framework provides a means for DNOs to plan investments at the distribution level that are attractive in terms of their combined capital and social[4] costs, and to negotiate (with Ofgem) proper distribution fees that would allow them to recover their capital costs. The combination of both capital and social costs (as recommended by Ofgem's CBA) implicitly introduces trade-offs, as network upgrade solutions meant to mitigate social costs typically result in increased capital expenditure, and vice versa. For instance, in order to reduce capital costs, the networks can be operated closer to margins to avoid investments in spare capacity, whereas additional capital expenditure in spare capacity may be recommended when carbon emissions and power losses (i.e., social costs) are internalised [12,13]. The CBA imposes a preferred level of trade-offs by assigning fixed economic values to emissions, reliability and other social aspects, which inherently undermines the case specific nature of trade-offs. Such an approach may be reasonable under traditional asset-based network reinforcement practices (e.g., based on line and substation upgrades) where large asset costs provide little flexibility for significant trade-offs between capital and social costs to emerge. However, this may not be the case in the face of emerging and highly flexible smart solutions (e.g., DR-based solutions) which, without explicit quantification and regulation of trade-offs, can result in inefficient investments in network solutions that result in no social benefits or significant capital expenditure. Accordingly, and given the fundamentally different "non-asset" nature of flexible solutions such as DR, a new framework that models trade-offs between asset and non-asset based solutions and thus also allows a like-for-like comparison with traditional planning models is needed.

The trend to update distribution network regulation to include social costs can be observed in other countries where, as recommended by the RIIO regulation, economic prices are assigned to the components of social costs (e.g., Finland, the Netherlands, Norway, Romania and Spain [14,15]). Similarly, the importance of smart grid technologies as a means to modernise the network and provide vital economic and social benefits is widely recognised [16]. Even though these smart solutions are generally deemed highly beneficial due to their potential to defer or avoid costly investments in capital-intensive assets, they can also lead to additional cost trade-offs associated with higher operational costs (e.g., DR payments) and increased power losses and emissions compared with traditional networks with upgraded lines and substations [17]. Regardless, the flexibility inherent in the smart solutions can, in principle, be used to balance the trade-offs if properly quantified and regulated. Accordingly, it is clear that existing regulation needs to be fully reviewed to recognise the new challenges faced by DNOs [18]. In fact, even though (i) regulation is aiming at integrating social costs in distribution planning (as highlighted above) and (ii) it is becoming apparent that the introduction of smart solutions can lead to significant trade-offs between capital and social costs relevant to distribution networks investments [19–21], to the best of the authors' knowledge, an approach to quantify and regulate these trade-offs has yet to be investigated.

In light of the above stated facts, the main contribution of this article is the proposal of a methodology to enhance Ofgem's CBA (or other regulatory frameworks) by providing it with a mechanism to explicitly quantify and regulate trade-offs between capital and social costs associated with business-as-usual and emerging smart network upgrade solutions (taking DR-based solutions as an example). More specifically, the business-as-usual practices are represented by traditional line and substation reinforcements. The smart solutions are represented by a new DR-based method that is currently under trial in the UK and that emerged due to regulatory support to facilitate innovation (i.e., the low carbon network fund [22]), namely the Capacity to Customers (C_2C) method [23]. The proposed methodology is used to assess cost trade-offs in 36 real distribution networks subject to different traditional and smart planning strategies. The results highlight that significant trade-offs between capital and social costs can emerge when smart solution become available and how their explicit assessment can provide a consistent means to compare, assess and plan distribution networks.

The rest of the article is structured as follows. An overview of traditional and emerging (smart) distribution network planning practices is presented. In Section 3, the proposed methodology is introduced, while its application and potential to quantify and facilitate the regulation of capital and social costs are illustrated with several real case studies in Section 4. The main conclusions of this work are presented in Section 5.

2. Distribution network planning practices

2.1. Traditional practices

In the UK, medium voltage (6.6 kV or 11 kV[5]) distribution networks have been traditionally planned and operated based on preventive security criteria, currently dictated by the P2/6 engineering recommendations. Accordingly, UK distribution networks must be redundant to facilitate the restoration of electricity supply to customers within a reasonable time frame after a credible contingency occurs.[6] Following these business-as-usual practices, typically two or more radial distribution feeders are interconnected through Normally Open Points (NOPs) creating open rings (see Fig. 1a). If a contingency were to occur in one of the radial feeders, all customers in that feeder would momentarily lose electricity supply (see Fig. 1b) while the contingency is isolated by the protection devises, typically within 3 min (see Fig. 1c). Afterwards, electricity supply would be restored to customers not directly connected to the fault by connecting them to a neighbouring feeder after manually closing the NOP, which normally takes an hour (see Fig. 1d). Finally, electricity supply would be restored to the customers directly connected to the fault by a repair crew who would manually isolate these customers from the fault and reconnect

[4] The mechanism used in Ofgem's CBA to internalize social costs is described in detail in Section 3.

[5] In the UK, medium voltage 6.6 kV and 11kV networks are conventionally indicated as high voltage (HV).

[6] Network reliability is regulated in terms of interruptions that last longer than 3 min.