Demand Response in Smart Distribution Network Planning: Regulatory Trade-offs between Capital and Social Costs

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Abstract

Under the current regulatory framework of the electricity distribution networks in the UK, new network 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, power losses and customer interruptions. This practice 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, particularly subject to the emergence of new network upgrade solutions based on Demand Response (DR) that introduce additional potential combinations of capital and social costs, which should be explicitly regulated. In this light, this paper proposes a methodology to explicitly model and quantify capital and social costs trade-offs, which can be incorporated into the existing distribution networks regulatory framework. The methodology is used to quantify capital and social costs under current conditions and subject to new smart solutions based on DR. The results, based on real UK distribution networks, show that by explicitly modelling and regulating the costs trade-offs according to our proposed methodology, it is possible to encourage more efficient levels of capital expenditure and social benefits.

Keywords**:** *Capital expenditure, carbon emissions, demand response, distribution network regulation, network reliability*.

1. INTRODUCTION

Since the privatization 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 (Pearson and Watson, 2012; Shaw et al., 2010; Simmonds, 2002). Early versions of the distribution regulation focused on reducing 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 emphasized the importance of different social costs associated with the distribution network such as electricity supply reliability, carbon emissions, and electrical power losses. This lead to trade-off between capital and social costs, as additional capital expenditure may be needed 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 throughout the distribution network, the electrification of heating (Navarro and Mancarella, 2014), 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 (Ofgem, 2009a, 2015a).

The new "Revenue = Incentives + Innovation + Outputs" (RIIO) network regulation model (from April 2015 to March 2023) (Ofgem, 2010, 2015b) 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 (Ofgem's CBA) to plan and assess distribution network upgrades as a part of the first RIIO regulation for electricity distribution (RIIO – ED1) (Ofgem, 2013a, 2013b, 2015c).

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[2] 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 (social costs) are internalised (Mancarella et al., 2011a, 2011b). The costs trade-offs are case specific and should be explicitly quantified and regulated to avoid conditions where DNOs may be encouraged to invest in network solutions that result in no social benefits or significant

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

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

capital expenditure. Such conditions may become more frequent due to the introduction of smart DR based solutions that may offer significant economic or social benefits, which can potentially encouraging DNOs to neglect social costs or disregard significant capital expenditure as long as it results in lower combined capital and social cost as estimated by Ofgem's CBA framework.

In the light of the above, this paper presents a methodology to enhance Ofgem's CBA by providing it with a mechanisms to explicitly quantify and regulate trade-offs between capital and social costs associated with business-as-usual and emerging DR based network upgrade solutions. The methodology is used to assess costs trade-offs in 36 real distribution networks subject to business-as-usual as well as to smart distribution network upgrade practices based on DR. 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; Ofgem, 2015d), namely the Capacity to Customers (C_2C) method (ENWL, 2015a). The explicit quantification and assessment of trade-offs between capital and social costs can facilitate a flexible regulation of distribution costs that adapts to the conditions of specific networks.

The rest of the paper is structured as follows. In Section 2, an overview of UK regulation for the distribution network is provided, placing special focus on the importance of capital and social costs, and innovation that lead to the RIIO price control. In Section 3, the C_2C method is presented and its potential impacts on expected capital expenditure and social costs are discussed. In Section 4, 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 5. In Section 6, the main conclusions of this research and the associated policy implications are presented.

2. UK DISTRIBUTION NETWORK REGULATION

Privatization of the UK electricity sector began in 1990 with the objective of minimising electricity costs via the introduction of competition. This allowed different private actors to take the roles of generators, retailers, transmission system operators, DNOs[3], and so forth, and compete with each other (Pearson and Watson, 2012; Shaw et al., 2010; Simmonds, 2002). However, actors taking the role of DNOs or transmission system operator naturally operate as monopolies, as it would be financially and sometimes technically prohibitive for other actors to build the transmission or distribution infrastructure required to compete with them. Accordingly, artificial competition between DNOs has to be introduced via specific regulations, such as the UK's price controls (Ofgem, 2013c).

In the UK, price controls dictate the maximum revenue that DNOs can accrue from distribution network charges levied on network users through suppliers. Generally, the proper price control for each DNO is estimated based on benchmarking (Burns et al. 2005; Frontier Economics, 2010). In other words, consistent and comparable metrics of the capital and social costs associated with the networks operated by the different DNOs are estimated and scaled based on the specifics of the networks and customers. This information is used to artificially introduce competition between the DNOs by setting individual price caps that allow them to make reasonable profits if their performance is similar to that of the most effective DNOs. Accordingly, the DNOs are encouraged to outperform each other with the aim of maximising their revenue subject to the price control.

The specific characteristics of the price control, particularly the metrics used to define the effectiveness of the DNOs, are periodically updated based on the ever changing national objectives and vision for the electricity sector. An overview of the historical evolution of UK distribution price controls is provided below.

2.1. Historical distribution price controls in the UK

Before privatization, the distribution network was considered inefficient and ill-planned due to associated high prices and poor quality of customer service. Accordingly, after privatization, early Distribution Price Control Reviews (DPCRs) were meant to facilitate cost efficiency by setting performance expectations and price caps for the DNOs (e.g., DPCR1 and DPCR2) (Pearson and Watson, 2012; Shaw et al., 2010; Simmonds, 2002). The price caps were indexed for inflation based on the Retail Price Index (RPI) and periodically reduced by an efficiency factor[4] (X), which is known as the RPI-X method (Mirrlees-Black, 2014). The efficiency factor is meant to simulate capital expenditure reductions due to efficient investments at the distribution level, and it is agreed between the DNOs and the regulator, (Ofgem since 2000). This approach provides strong incentives for DNOs to reduce costs, as the price control is fixed during the whole price control (i.e., 5 years until 2015 and 8 years afterwards).

This approach indeed resulted in significant reductions in capital expenditure, although it provided little social costs mitigation and resulted in a significant decline in innovation, which is deemed a costly and risky activity subject to the RPI-X model. In 2000 Ofgem became the new DNO regulator and placed greater focus on social costs, customer engagement and the effects of uncertainty. As a result, incentives to minimise electrical losses and improve the quality of supply for customers emerged, along with uncertainty mechanisms to update the price control should the price cap become ineffective due to an unexpected event at the distribution level. By the end of DPCR3 in 2005, distribution network charges were reduced by roughly 50% (Buchanan, 2008). However, part of these savings could be attributed to a reduction in the work force of DNOs and reduced maintenance and replacement of distribution infrastructure (Shaw, 2010).

At this stage, driven by raising environmental concerns, the potential role that the distribution networks could play as enablers for social costs mitigation started drawing attention, particularly as low carbon and renewable

[3] Currently, there are 14 licensed DNO in the UK owned by 6 different companies.

[4] The X factor has historically varied between 1.1 and -3 in the UK.

Table 1: Overview of the different UK price controls since privatization.

<table>
<tr><td>DPCR1
1990-95</td><td>DPCR2
1995-2000</td><td>DPCR3
2000-05</td><td>DPCR4
2005-10</td><td>DPCR5
2010-15</td><td>RIIO-ED1
2015-23</td></tr>
<tr><td colspan="2" rowspan="9">Fixed income</td><td colspan="4">Uncertainty mechanisms</td></tr>
<tr><td colspan="4">Quality of supply incentives</td></tr>
<tr><td colspan="2">Interview based customer satisfaction measures</td><td colspan="2">Broad measure of customer satisfaction</td></tr>
<tr><td colspan="2">Losses incentive</td><td colspan="2">Losses reporting</td></tr>
<tr><td rowspan="2"></td><td colspan="2">Innovation funding incentive</td><td rowspan="2">Innovation stimulus package</td></tr>
<tr><td></td><td>Low carbon network</td></tr>
<tr><td rowspan="2"></td><td rowspan="2"></td><td colspan="2">Operation and capital expenditure incentives</td></tr>
<tr><td colspan="2">Workforce renewal incentives</td></tr>
<tr><td></td><td></td><td></td><td>CBA framework</td></tr>
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generation technologies were emerging at the distribution level (HMSO, 2003; Sinclair and Thomas, 2003). In addition, the lack of research and development was recognised as an issue, which lead to the creation of the innovation funding incentive during DPCR4 and to effectively encourage DNOs to retake research and development activities (Ofgem, 2007). During the latest price control (DPCR5) greater capital expenditure was finally allowed to upgrade the aging networks (i.e., incentives to balance capital and operational expenditure were introduced), while greater focus was placed on minimising social costs such as those associated with power losses and carbon emissions. Further innovation has been encouraged with the low carbon network fund (Ofgem, 2015d).

2.2. RIIO-ED1

Nowadays, the distribution network is facing even greater challenges due to the increasing penetration of intermittent renewable sources. Accordingly, the new RIIO price control is placing significant emphasis on innovation such as the deployment of DR as a means for achieving desired outputs (e.g., social cost reduction targets) at reasonably low capital costs, while coping with existing and emerging challenges at the distribution level (Ofgem, 2009b, 2015b).

In accordance with the first version of the RIIO price control for electricity distribution (RIIO-ED1; Ofgem, 2015c), DNOs are expected to meet a range of social targets in terms of network reliability, carbon emission reductions, and so forth using both business-as-usual and smart solutions. The later will now be encouraged with an innovation stimulus package comprising three schemes (Ofgem, 2015e), namely (i) the network innovation competition, which aims at facilitating the formulation and assessment of smart and promising distribution solutions; (ii) the network innovation allowance, which focuses on small-scale innovation projects; and (iii) the innovation roll-out mechanism, which funds the roll-out of proven new smart solutions. This stimulus package can be used by DNOs to finance innovation projects that offer potentially attractive benefits at the distribution level, thus avoiding penalties for the DNO should the outcomes of the project be economically unattractive. In addition, as part of RIIO-ED1, Ofgem is introducing a CBA framework for the planning and assessment of distribution network solutions. Ofgem's CBA is meant to provide consistent and comparable metrics of the capital and social costs associated with investments made by different DNOs, and thus facilitate regulation. A summary of the different UK price controls is presented in Table 1.

Based on the above, the new RIIO price control will place a great focus on mitigating both capital and social costs, particularly via the use of innovative distribution solutions. For this purpose, the new innovation stimulus package is expected to encourage a sustainable development of innovation at the distribution level, whereas Ofgem's CBA framework will encourage DNOs to invest in network upgrades that facilitate capital and social costs reductions.

3. SMART DISTRIBUTION LEVEL SOLUTIONS

In this work, the C_2C method is selected to represent new smart distribution level solutions. The C_2C method was chosen to represent smart solutions mainly for four reasons, namely: (i) its potential to significantly reduce capital expenditure compared with business-as-usual solutions via DR deployment; (ii) it includes solutions to mitigate social costs; (iii) it is currently under trial in real UK distribution networks; and (iv) it was funded by the low carbon network fund (Ofgem, 2015d) as a promising new smart grid solution to tackle emerging challenges a the distribution level.

Based on the above, this section provides an overview of traditional distribution network practices (including potential room for improvements which led to the proposal of the C_2C method) as well as a detailed description of the C_2C method and the underlying smart solutions.

3.1. Traditional distribution network planning practices

In the UK, medium voltage distribution networks (with nominal voltages equal to 6.6 kV or 11kV[5]) have been traditionally planned and operated based on preventive security criteria, currently dictated by the P2/6 engineering recommendations (Allan et al., 2013). Accordingly, the distribution networks must be redundant enough to be capable of restoring 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 Figure 1a). If a contingency were to occur in one of the radial feeders, all

[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 minutes.

customers in that feeder would momentarily lose electricity supply while the contingency is isolated by the protection devises, typically within 3 minutes (see Figure 1b). 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 Figure 1c). 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 them to the network or to a mobile electricity generator while the fault is cleared.

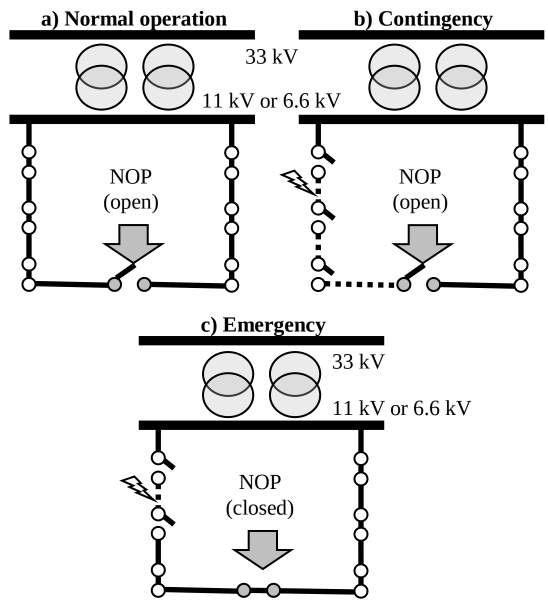

Figure 1: Business-as-usual high voltage network restoration in the UK.

In order for the business-as-usual distribution network planning strategy to work, large capital investments are needed to significantly oversize each feeder so that enough spare emergency capacity is available to supply own load as well as customers in neighbouring feeders. However, the spare emergency capacity is seldom used as the frequency of contingencies is relatively low. More specifically, on average a contingency is expected every three years, and there are several networks where contingencies have never been registered (ENWL, 2015c). Therefore, on the one hand it would be economically attractive to avoid investing in additional emergency capacity in some networks, as it is seldom or never needed. On the other hand, without the emergency capacity, customers may be exposed to infrequent but theoretically long. Accordingly, the investments in spare emergency capacity could only be averted with a solution that protected customers from lengthy.

3.2. The Capacity to Customers method

After assessing the drawbacks of business-as-usual planning practices and reviewing new smart solutions at the distribution level (e.g., Lueken and Carvalho, 2012; Pudjianto et al., 2013; Poudineh and Jamasb, 2014), Electricity North West Limited (ENWL) proposed the C_2C method in 2011 as a combination of smart grid solutions that may bring about significant capital savings in terms of avoided investments in emergency capacity as well as social savings in terms of reduced customer interruptions, power losses and carbon emissions (ENWL, 2015a, 2015b). In order to achieve this, the C_2C method includes three smart solutions as described below:

1. Network reconfiguration: The NOP is operated normally closed during normal operations creating a closed ring. This is can expected to result in an immediate reduction of electricity losses and the associated carbon emissions in most cases.
2. Network automation: The NOP and strategic location in each feeder are automated to facilitate rapid and automatic network restoration after contingencies occur. This is expected to reduce customer interruptions for more than 3 minutes, which are the only interruptions regulated in the UK (Ofgem, 2012). In fact, the ring configuration would normally expose more customers to interruptions, as customers in both feeders would be affected by contingencies in either feeder. However, the increased automation levels allow the network to be operated as a ring while still reducing interruptions for longer than 3 minutes. This has been corroborated by C_2C customer trials to date.
3. Post-contingency DR deployment: DR can be deployed after a contingency occurs to reduce the demand in the network during emergencies. As a result, part (or all) the emergency capacity put in place for security reasons would not be required. As a result, due to the availability of post-contingency DR, new investments in spare security capacity can be deferred or even avoided.

Due to its potential attractiveness to improve current distribution planning practices and lead to capital and social costs savings, the C_2C project was granted funding under the low carbon network fund in 2011 (Bidwell, et al., 2012). The C_2C method is currently under trial in 200 UK distribution networks (i.e., 153 closed rings, 27 open rings and 20 radials), among which 36 networks are being monitored and modelled in detail. Results from these 36 networks are presented in this study.

4. METHODS

The capital and social costs trade-offs associated with distribution network upgrades are a function of the corresponding regulation in place. As part of the new RIIO-ED1 price control, Ofgem has introduced a new CBA for the assessment of distribution network interventions, which quantifies capital costs and also internalises social costs such as those associated with power losses, carbon emissions and reliability.

Ofgem's CBA provides different DNOs with a consistent and comparable means for assessing asset built. However, by internalising social costs, it introduces trade-offs between the typically opposing objectives of reducing capital expenditure and investing in social costs mitigation solutions. Furthermore, Ofgem's CBA does not quantify the impacts that social costs mitigation can have on capital expenditure in particular conditions, and vice versa. As a result, the CBA framework may encourage significant capital expenditure or little social benefits in some cases, which is not in line with the objectives set in the RIIO regulation.

Based on the above, a methodology to extend Ofgem's CBA to assess costs trade-offs is proposed in this work. The proposed tool provides explicit metrics of capital expenditure, social costs and trade-offs, which can be used to assess and regulate asset built at the distribution level.

4.1. Ofgem's CBA

Based on Ofgem's CBA, the total capital costs ($Cdno_y$) incurred by DNOs due to investing in one of the n-th available network upgrade solutions ($I_{n,y}$) in a given year (y) (i) the expensed investment ($Iexp_y$), which is a part of the investments that can be recovered immediately; (ii) depreciation (Dep_y), which is a part of the capitalized investment ($Icap_y$) that can be recovered over time divided by a depreciation lifetime ($Tdep$) assumed to be 45 years; and (iii) the cost of capital (CC_y), which is a profit margin based on the regulated asset value RAV_y and the pre-tax Weighted Average Cost of Capital ($WACC$). This procedure is summarized by (1) – (5) (Ofgem, 2013a).

$$Cdno_y = Iexp_y + Dep_y + CC_y \tag{1}$$

$$Iexp_y = 0.15 \times \sum_{n=1} I_{n,y} \tag{2}$$

$$Dep_y = \sum_{y1=1}^{y} \frac{Icap_{y1}}{Tdep} \tag{3}$$

$$CC_y = RAV_y \times WACC \tag{4}$$

$$Icap_y = 0.85 \times \sum_{n} I_{n,y} \tag{5}$$

$$RAV_y = Icap_y - Dep_y - RAV_{y-1} \tag{6}$$

The total social costs ($Csoc_t$) associated with a particular network upgrade solution are calculated from (7) as the sum of costs associated with losses ($Closs_t$), emissions ($Cco2_t$), customer interruptions (Cci_t) and customer minutes lost ($Ccml_t$)[7].

$$Csoc_t = Closs_t + Cco2_t + Cci_t + Ccml_t \tag{7}$$

Finally, the annual capital and social costs are discounted (discount rates (d) of 3.5% and 3% are used for cash flows within 30 years and between 31 and 45 years in the future, respectively) to produce capital (NPC_C), social (NPC_S) and combined capital and social (NPC_{C+S}) costs metrics presented in (8), (9) and (10), respectively (Ofgem, 2013a). The combined capital and social costs metrics (NPC_{C+S}) are used by DNOs to plan relevant network upgrades and justify the relevant capital expenditure metrics (NPC_C) that are used to negotiate with Ofgem adequate network fees to recover their costs.

$$NPC_C = \sum_{t=1} \frac{DNO\_costs_t}{(1+d)^t} \tag{8}$$

$$NPC_S = \sum_{t=1} \frac{Social\_costs_t}{(1+d)^t} \tag{9}$$

$$NPC_{C+S} = NPC_C + NPC_S \tag{10}$$

In practice, DNOs may maximise their benefits subject to a given price control if investment decisions would be based on the NPC_C criterion. This would potentially lead to reductions in capital expenditure (and eventually to lower customer charges) at the expense of increasing social costs (sometimes significantly) at the distribution level. However, distribution network upgrades should be justified to Ofgem in terms of the NPC_{C+S} criterion, which can lead social costs mitigation as well as to significantly higher capital expenditure in some conditions.

Considering the objectives set by the new RIIO-ED1 regulation, it is attractive to facilitate social costs mitigations without substantially increasing capital expenditure. This could be achieved by extending Ofgem's CBA with a mechanism to explicitly assess and regulate trade-offs between capital and social costs, as the one proposed in this work and described below.

4.2. Proposed methodology

The assessment of trade-offs between multiple objectives is a well-known topic in the area of decision planning, particularly multi-criteria and multi-objective planning (Zopounidis and Pardlos, 2010). Generally speaking, the most typical techniques used to address trade-offs are based on either weights or constraints. The former would involve using weights to redefine the value of different types of social costs, which is debatable, and may result in inconsistent metrics (unattractive for regulation) as a relatively different NPC_S and NPC_C would be defined for each study. The latter involves using constraints to redefine the strategies to deploy different interventions (e.g., the C_2C method, and line and substation reinforcements), and would not affect the current definitions of the NPC_C or NPC_S, which makes this approach more attractive form a regulatory perspective.

Based on the above, the trade-offs between capital and social costs are modelled below by constraining additional capital expenditure. That is, sets of investment strategies that result in different combinations of social and capital costs are defined by constraining maximum capital expenditure. Such an approach would require the DNOs to produce several investment strategies to be assessed by the tool, which is also required by the current version of Ofgem's CBA to justify the

[7] It is worth noting that the CBA allows the modelling of other social costs such as risk of injury and environmental impacts of using particular types of oils for the transformers. These are not discussed in this paper as they are not relevant to the type of DR-based smart grid distribution network interventions considered in this work.

selection of a given strategy. A high level description of this process is presented in Figure 2. The process begins by defining potential network upgrade solutions, such as traditional line and substation upgrades and the C_2C method. Afterwards, the application of each solution in different years of the planning horizon (45 years according to Ofgem's CBA) may be recommended based on technical, economic or social considerations. Finally, every potential upgrade solution would have been assessed in terms of the relevant NPC_{C+S}, NPC_C and NPC_S.

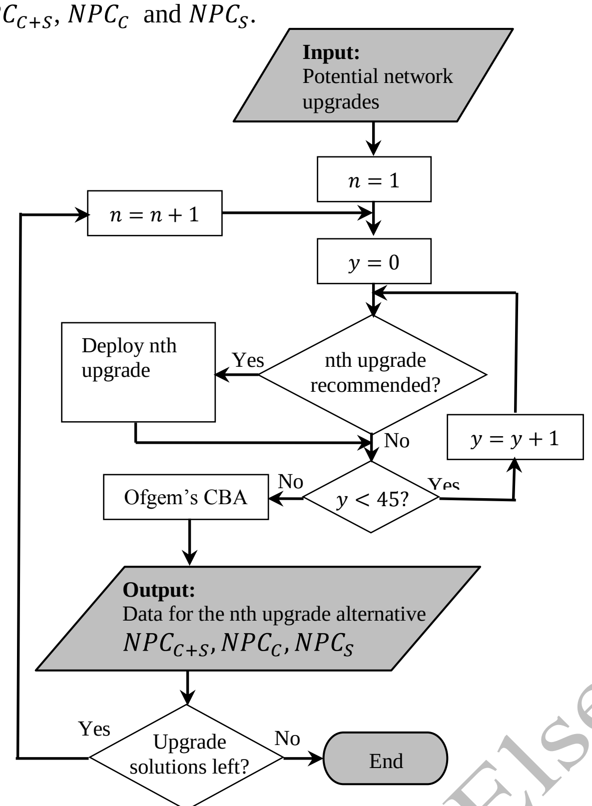

Figure 2: High level description of the traditional formulation of distribution network upgrade planning practices.

However, in this work, rather than manually formulating the different strategies based on the process shown in Figure 2, and optimisation engine is adopted. The advantages of using an optimisation engine are that it provides systematic, comprehensive and replicable means to assess all available network upgrade solutions. The engine is based on exhaustive searches to assess all feasible interventions that could be deployed and select the best strategy. See (Martinez and Mancarella, 2014a, 2014b) for a more technical and detailed description of the optimisation engine.

Based on the above, the methodology proposed in this work combines capital expenditure constraints and an optimisation engine[8] to provide Ofgem's CBA with a mechanism to assess and regulate trade-offs between capital and social costs. A high level description of the proposed methodology is presented in Figure 3.

[8] The optimisation engine can be replaced by the series of studies that DNOs would normally do to comply with Ofgem's CBA and which are represented in Figure 2.

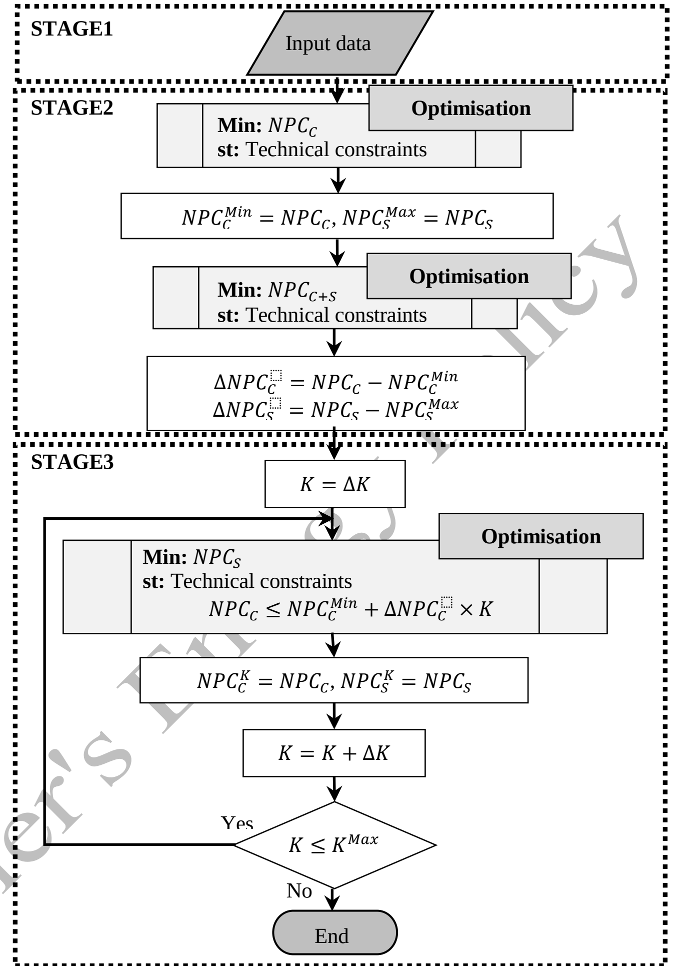

Figure 3: High level flow diagram of the proposed methodology.

At stage 1, the methodology begins by collecting all the inputs required by Ofgem's CBA, which broadly speaking include a description of all investment strategies considered (e.g., combinations of the C_2C method and line and substation reinforcements) in terms of the associated initial and periodic capital expenditure, power losses, emissions, customer interruptions, and so forth. This information has to be forecasted on an annual basis for 45 years (currently from 2015) based on a best-view forecasts of expected demand growth in the distribution network. See (Ofgem, 2013a, SP Energy Networks, 2014) for a detailed description of the different inputs required to populate Ofgem's CBA

At stage 2, the methodology aims at identifying adequate values to constraint capital expenditure so that attractive combinations of capital and social costs can be identified and the corresponding trade-offs assessed. For this purpose, a two stages process is used. Firstly, an investment strategy that minimises capital expenditure without regard for social costs is identified by using the NPC_C criterion described by (8) as the objective function for the optimisation engine. The result of this process would be the network upgrade strategy with the lowest capital costs (NPC_C^{Min}) and the highest social costs (NPC_S^{Max}). It is important to note that even higher social costs may be achieved via more capital expensive network upgrades; however, such upgrades can be disregarded as they would not be recommended by DNOs or Ofgem's CBA. Secondly, a new investment strategy is formulated, now with the objective of minimising the relevant NPC_{C+S}. Compared with the previous investment strategy, the capital costs associated with the new strategy would be ΔNPC_C higher while the social costs would be ΔNPC_S (ΔNPC_S is negative) lower as represented by (11).

$$NPC_{C+S} = NPC_C^{Min} + \Delta NPC_C + NPC_S^{Max} + \Delta NPC_S \quad (11)$$

Equation (11) captures extreme costs trade-offs associated with transitioning from planning network upgrades selected based only on the objective of minimising capital costs to also internalising social costs as recommended by Ofgem's CBA framework. As discussed throughout this paper, the attractiveness of these alternatives is case specific and may lead to high capital costs or little social benefits under specific conditions. In such cases, other upgrade alternatives that offer different combinations of capital and social costs may be more attractive, for instance by providing most social benefits at a fraction of the capital expenditure. In order to identify alternative upgrade strategies that may offer attractive combinations of capital and social costs (between the extreme costs set when optimising based on the NPC_C and NPC_{C+S} criteria), capital expenditure associated with upgrades for social costs mitigation can be constrained using a constant K ($\in [0,1]$) as shown in (12).

$$NPC_C \leq NPC_C^{Min} + \Delta NPC_C \times K \quad (12)$$

At stage 3, new investment strategies that offer different combinations of capital and social costs are formulated by constraining maximum capital expenditure with (12) and using the optimisation engine to formulate strategies that minimise social costs (i.e., NPC_S). Different costs trade-offs can be produced by varying the constant K between zero and one, which result in minimum capital and social costs, respectively.

The outputs of the methodology are sets of investment strategies that lead to different costs trade-offs in the form of potential combinations of capital and social costs. This information can be used to identify and regulate costs trade-offs in distribution network upgrades by, for instance (i) selecting the most cost-effective strategy in terms of unit of social cost reduction per unit of additional capital spent (i.e., $\Delta NPC_S/\Delta NPC_C$), (ii) the most socially attractive strategy subject to a maximum capital expenditure allowance, (iii) the most economical strategy that provides at least the same social mitigation as business-as-usual solutions, and so forth. This will be further discussed and illustrated in the next section.

5. Case study, results and discussion

In this section, the proposed methodology is used to investigate potential trade-offs between capital and social costs associated with traditional business-as-usual and smart DR based solutions at the distribution level in the UK. The methodology is applied to several case studies comprising 2 cases, 36 real distribution networks and 5 demand growth scenarios.

The two cases considered are referred to as the Base case and the C_2C case. In the Base case, only traditional line and substation reinforcements are considered as network upgrade alternatives, and demand is considered passive and dictated by a demand growth scenario. This case is used as a baseline as it represents business-as-usual practices. In the C_2C case, DR and network automation and reconfiguration can be deployed as alternatives to or in combination with traditional line and substation reinforcements. This case is used to represent the effects that DR based smart solutions can have at the distribution level. The distribution networks considered in this study are the 36 real networks currently being monitored and modelled in detail as part of the C_2C trials (ENWL, 2012, 2014). The 5 demand growth scenarios considered were formulated by the DNO that proposed the C_2C method (Electricity North West) as potential best-view forecasts for demand growth in the 36 trial networks (Martinez and Mancarella, 2015).

The methodology is illustrated and some preliminary conclusions are drawn using a single network and a scenario. Afterwards, the findings are expanded based on the assessment of all 36 networks in different scenarios.

5.1. Single network assessment

Consider the two feeders of the Clover Hill 6.6 kV distribution network shown in Figure 4. This network is connected to a 20 MW substation and supplies 3327 customers (mostly urban customers).

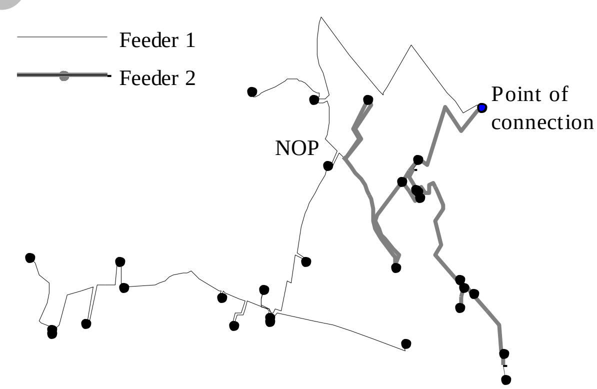

Figure 4: Clover Hill distribution network.

Assume the demand growth scenario presented in Figure 5 and the Base case where only traditional line and substation reinforcements are available (this information is used to populate the methodology as part of stage 1). As part of stage 2, considering the capital costs minimisation criterion (NPC_C), the lines should be upgraded in 4 years and once more in 17 years, whereas the substation should be reinforced in 15 years. Note that investments are proposed few years before reaching firm capacity due to the construction lead time associated with the intervention (i.e., 2 and 3 years for line and substation reinforcements, respectively). This investment strategy results in a capital cost (NPC_C) of 289 k£ and a social cost (NPC_S) of 698 k£. In this case, the recommended scheme and associated capital and social costs do not change (i.e., ΔNPC_C= 0) even after internalising social costs based on the NPC_{C+S} criterion as recommended by Ofgem's CBA framework. That is, in this case, business-as-usual practices under current regulation result in no social costs mitigation.

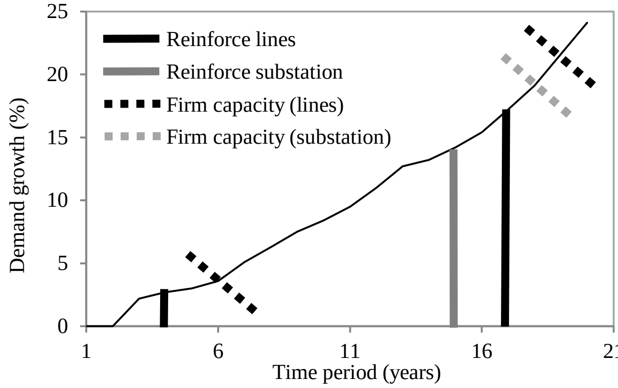

Figure 5: Investment strategy for the Clover Hill network considering the base case, capital cost minimization and Scenario 1.

Now, consider the C_2C case where C_2C interventions can be deployed as well as traditional line and substation reinforcements. In this case, the NPC_C and NPC_{C+S} criteria result in fundamentally different strategies. As shown in Figure 6, based on the NPC_C criterion that neglects social costs, a C_2C intervention with a lead time of a year is recommended in year 5 to defer the first line reinforcement to year 5 and avoid the second line reinforcement as well as the substation reinforcement compared with the Base case. As a result, capital expenditure is reduced to 253 k£ compared with 289 k£ in the Base case, and social costs increase to 713 k£ compared with 698 k£ in the Base case. Based on the NPC_{C+S} criterion (see Figure 7), the C_2C intervention is rushed to year 1 to maximise social benefits. As a result social costs decrease to 561 k£ (ΔNPC_S= -152 k£) while capital costs increase to 289 k£ (ΔNPC_C= 36 k£), which is roughly the capital costs associated with the Base case.

The results so far show that the use of a smart DR based network upgrade solution has introduced attractive capital and social costs trade-offs that could lead to reduced capital expenditure and social costs compared with the base case. However, if on the one hand DNOs were allowed to use the C_2C exclusively to reduce capital costs at the distribution level[9] (i.e., using the NPC_C criterion or setting $K = 0\%$), the social costs associated with the Clover Hill network would increase compared with those of the Base case. On the other hand, if social costs are internalised based on current regulations (i.e., using the NPC_{C+S} criterion or setting $K = 100\%$), the DNO would not be able to reduce capital expenditure compared with the Base case. Both conditions can be deemed unattractive either from the social or economic perspectives.

Alternative network upgrade strategies that offer new combinations of capital and social costs can be defined using the rest of the methodology (stage 3). In this example, the designs are formulated by setting *K*= [0% 25% 50% 75% 100%] in (12). The results, presented in Figure 8 and Table 2, illustrate different trade-offs between capital and social costs associated with the Base and C_2C cases. Note that the Base case is not presented in the table as the relevant capital and social costs do not change in this example.

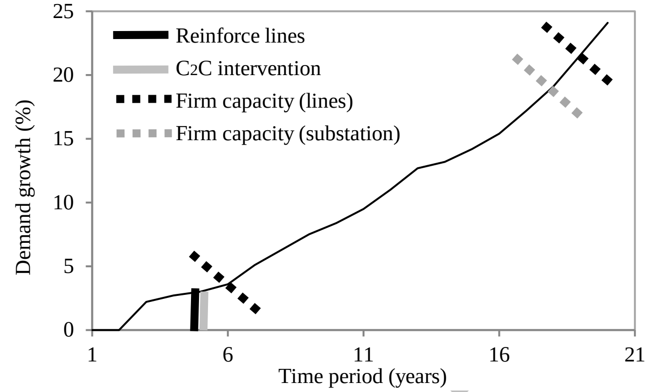

Figure 6: Investment strategy for the Clover Hill network considering the C_2C case, capital cost minimization and Scenario 1.

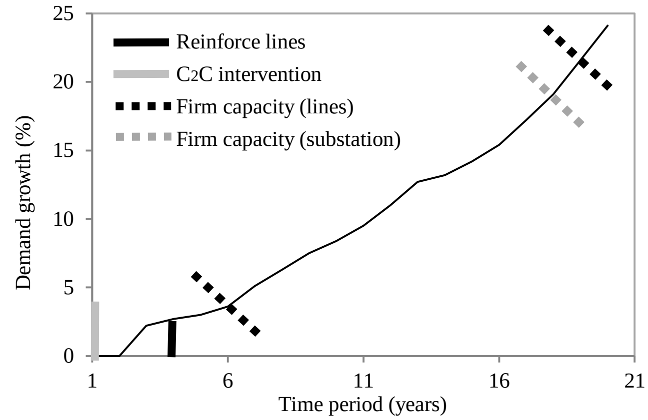

Figure 7: Investment strategy for the Clover Hill network considering the C_2C case, capital and social cost minimization and Scenario 1.

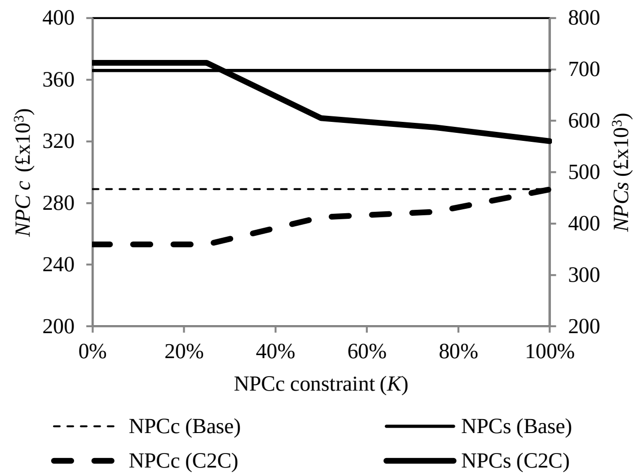

Figure 8: Capital and social costs trade-offs for the Clover Hill network considering Scenario 1 and variants of the social costs mitigation mechanism.

[9] The prospect of deploying DR to reduce capital expenditure in costly network reinforcements was one of the main reasons for the development of the C_2C method.

Table 2: NPC variations associated with the C_2C case for the Clover Hill network.

K	C_2C case		
	ΔNPC_C	ΔNPC_S	$\Delta NPC_S/\Delta NPC_S$
0%	0 k£	0 k£	0
25%	0 k£	0 k£	0
50%	18 k£	108 k£	6.14
75%	21 k£	126 k£	5.95
100%	36 k£	153 k£	4.28

The outputs of the proposed methodology are the explicit identification of alternative network upgrade solutions that offer different costs trade-offs (as shown in Figure 8 and Table 2). This information can facilitate the identification of capital and social costs combinations that may be more attractive than those preferred from the perspective of capital expenditure and current regulation. For instance, in this example, it may be attractive to limit additional capital expenditure to 18 k£ (50%) to achieve a social cost reduction of 108 k£, which corresponds to 70% of the maximum potential social costs reduction and 6.14 times the additional capital expenditure (i.e., the most cost effective solution in terms of $\Delta NPC_S/\Delta NPC_C$). Alternatively, other metrics can be used to regulate the costs trade-offs such as setting a maximum additional capital expenditure allowance (e.g., $K = 75\%$) or selecting a strategy that provides at least the same social costs mitigation as the Base case (i.e., $K = 30\%$). The metrics provided by the methodology can be incorporated into current regulations to facilitate more attractive combinations of capital expenditure and social costs associated with distribution network upgrades. This is a key contribution of this research work.

Based on the results presented in this example, it is possible to draw four preliminary findings as detailed below.

1. The existing network regulation tends to encourage relatively little social cost mitigation and capital expenditure increase subject to current business-as-usual practices.
2. The introduction of DR based smart solutions may offer new combinations of capital and social costs that could facilitate attractive social and capital costs mitigation if the associated trade-offs are explicitly quantified and regulated.
3. Under the current regulatory framework, the introduction of new DR upgrade alternatives such as the C_2C method may facilitate significant social benefits at the expense of limiting the associated capital benefits.
4. The proposed methodology can facilitate the regulation of cost trade-offs.

5.2. Wider network assessment

In this section, the case study is extended to 36 UK distribution networks and 5 demand growth scenarios (Martinez and Mancarella, 2015) to elaborate and corroborate the four initial findings presented in the previous case study. The main results of the complete case study are presented in Figure 9. The figure presents the average NPC_S and ΔNPC_S (solid lines), and NPC_C and ΔNPC_C (dashed lines) associated with the Base case (square markers), C_2C case (triangle markers) and the difference between both cases (rhombus markers), subject to different capital expenditure constraints (K).

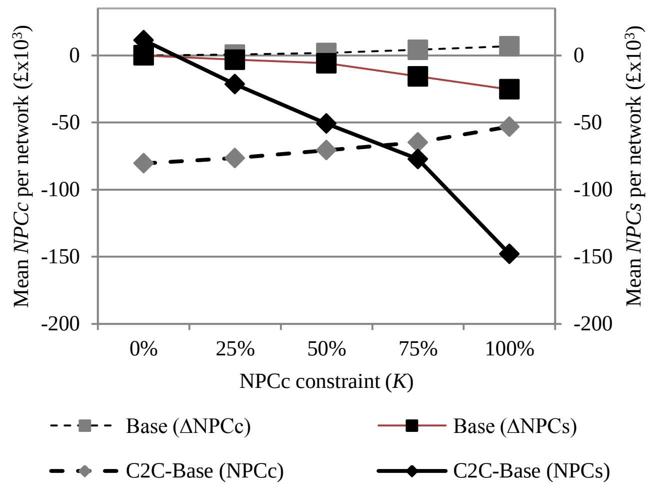

Figure 9: Comparison of the Base case and C_2C case in terms of the NPC_C, NPC_S, ΔNPC_C and ΔNPC_S.

The first initial finding, namely the relatively little potential for social costs mitigation (but also little increase in capital expenditure) under the current regulatory framework and subject to business-as-usual practices, can be corroborated by observing the performance of the Base case (square markers) in terms of the ΔNPC_C and ΔNPC_S when $K = 100\%$. In this example, social costs are reduced in average by 25 k£ per network, whereas capital expenditure only increases by 7 k£ per network.

The second initial finding suggests that the introduction of DR based network upgrade options (e.g., the C_2C method) can facilitate new potentially attractive capital and social costs combinations. This can be corroborated by comparing the costs associated with the Base and C_2C cases (rhombus markers). As shown, the C_2C case offers several combinations of capital and social costs that are lower than those of the Base case, even without fully internalising social costs as recommended by Ofgem's CBA framework. Accordingly, it would be possible to outperform the social costs mitigation potential of business-as-usual practices while still achieving significant capital benefits (e.g., grey rhombus markers at $K = 50\%$ or 75%).

However, as highlighted by the third initial finding, under current regulations the C_2C method would be deployed mostly to facilitate social costs benefits at the expense of limiting the potential of DR to reduce capital expenditure. As shown in Figure 9, the C_2C method can facilitate an average reduction of social costs of 148 k£ per network (black rhombus marker at $K = 100\%$). This would reduce the potential of the C_2C method to reduce capital costs from roughly 80 k£ (grey rhombus marker at $K = 0\%$) to about 50 k£ (grey rhombus marker at $K = 100\%$). This is may be unattractive for DNOs; although it can be argued that it is acceptable form a welfare perspective as total capital expenditure is still lower than that of the Base case (i.e., DNOs can still minimise capital expenditure). However, this is not always the case as shown in the case study presented in Section 5.1 where the DNO would be unable to make any capital saving. In fact, as shown in Figure 10[10], there are several conditions within the scope of this study where the introduction of the C_2C method resulted in an increase of capital expenditure compared with the Base case (33% of the cases), which can be of more than 50 k£ in extreme conditions. In regard to these conditions, it may be particularly attractive to expand the current distribution network regulatory framework with a mechanism to addressed costs trade-offs in case specific applications as the tool presented in this work.

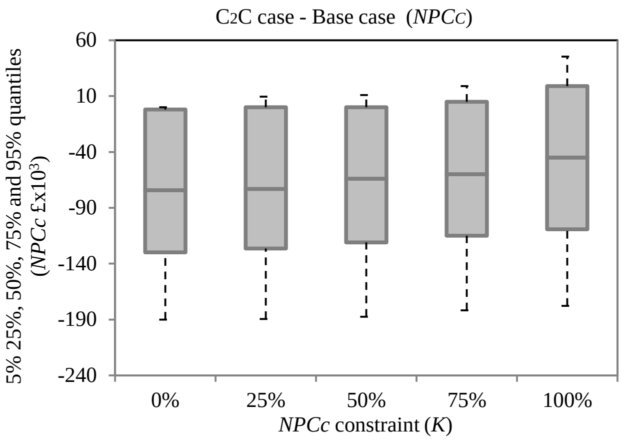

Figure 10: Comparison of (NPC_C) capital costs between the C_2C and Base cases.

As hinted by the fourth initial finding, the proposed methodology can facilitate the identification of attractive combinations of capital and social costs, and could be included in the current distribution network regulatory framework. The main feature of the proposed approach is that it allows the identification of different investment alternatives that result in a variety of social costs savings subject to a maximum capital expenditure ΔNPC_C). As a result, it is possible to assess different strategies with the aim of identifying the option that provides the most attractive social costs savings at the lowest capital cost. As discussed in the example, the tool can be used to identify the least cost solution that offers attractive social cost reductions that are equal to or greater than those estimated for the Base case subject to current regulations ($K = 100\%$). This would result in limiting additional capital expenditure to 25% under most conditions considered within this study. Alternatively, the tool can be used to find the most efficient costs trade-off in terms of $\Delta NPC_S/\Delta NPC_C$ (see Figure 11), which can be achieved under most conditions under consideration by limiting additional capital expenditure to 50%. Ultimately, the expenditure and social cost reduction targets and trade-offs would be selected by policy makers based on national targets and/or political reasons, and the use of a methodology to quantify these costs trade-offs would be required to address the particular characteristics of specific networks.

[10] The figure shows the occurrence of different conditions (in terms of quantiles) where different levels of additional capital expenditure where achieved by moving from the Base to the C_2C case.

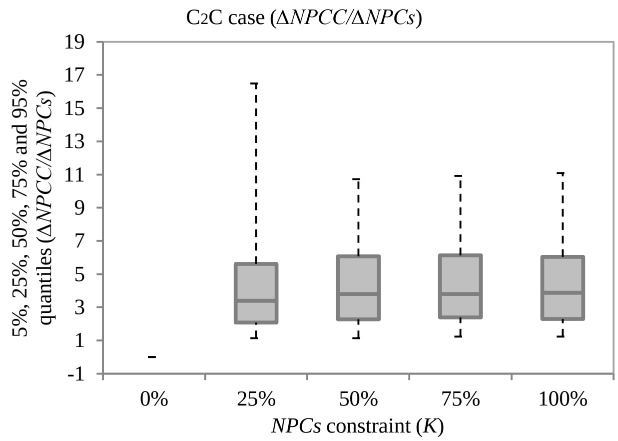

Figure 11: Capital and social cost trade-offs (ΔNPCs/ΔNPCc) associated with the C_2C case.

6. CONCLUSIONS AND POLICY IMPLICATIONS

New emerging challenges at the distribution level brought about by environmental concerns and technological innovations are forcing regulations to step back from focusing majorly on efficient investments and place greater focus on motivating innovation to meet desired outputs. The UK regulator is aiming at achieving this via the introduction of economic incentives to facilitate new smart solutions typically based on DR deployment (e.g., the low carbon network fund which supported the development of the C_2C method) and the new RIIO-ED1 price control, which offers mechanism to facilitate capital and social cost reductions at the distribution level, namely Ofgem's CBA.

As discussed throughout this paper, under current UK distribution network regulations, DNOs are meant to internalise social costs when planning network upgrades, which. This mechanism (i.e., Ofgem's CBA) inherently introduces trade-offs between capital and social costs, as network upgrade solutions meant to mitigate social costs typically result in increased capital expenditure, and vice versa. These trade-offs become more significant after the introduction of smart DR based network upgrade solutions, which may offer additional combinations of social and capital costs. These smart solutions can offer significant social costs savings at the expense of significant capital costs under some conditions, which should be properly addressed by emerging regulatory mechanisms. Accordingly, this paper proposes a methodology meant to extend current UK regulation (specifically Ofgem's CBA) to address cost trade-off in light of smart solutions.

The proposed methodology can be used by DNOs to produce curves detailing capital and social costs trade-offs associated with asset built at the distribution level. These curves can be used to inform a regulatory mechanism that may select the most attractive investment strategy based on expected social cost reductions, maximum additional capital expenditure allowance and/or cost-efficiency targets. For instance, the mechanism could select the least capital expensive strategy that offers the same social benefits as the business-as-usual interventions that would be selected by the current version of Ofgem's CBA. Such a mechanism could facilitate meeting social targets (e.g., losses reductions at the distribution level) at a low capital cost. However, the details of the mechanism would ultimately be based on the main objectives set by Ofgem for the distribution sector, which would reflect national goals.

As a final remark it is worth noting that the proposed methodology can be attractive to regulate capital expenditure and social costs in other regulatory contexts or even for monopolies; particularly as smart DR based solutions have been emerging in the electricity sector worldwide due to the smart grid paradigm. DNOs may be required to perform additional network upgrade studies (unless a framework similar to Ofgem's CBA is already in place) or to adopt an optimisation engines in order to apply the proposed methodology. Regardless of these potential additional studies, the prospect of minimising capital expenditure while meeting social cost targets can facilitate the adoption of the proposed methodology or similar approaches by DNOs.

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