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Abstract

This paper quantifies the benefits of introducing reactive power markets that promote the participation of distributed energy resources (DER) in a coordinated way, between the electricity system operator and the electricity distribution utilities. The contribution that DER could make by displacing conventional network assets in supplying reactive power support is evaluated in the context of a case study, the Power Potential (PP) project in Great Britain. We discuss the rising need for absorptive (leading) reactive power in the PP trial area, driven by the rapid connection of renewable generation in an area of low demand growth. A social cost benefit analysis (SCBA) is performed to quantify the net benefits, with sensitivities regarding bid prices, % of DER participation, time horizons. Price information from the PP live trial conducted between January and March 2021 is also used to evaluate the robustness of the SCBA and to estimate benefits using actual prices. Our results suggest that energy consumers could save from 8-21% of business as usual asset costs by 2050. The introduction of trial bid prices increases these savings by around 3% of business as usual asset costs out to 2050. Potential sources of additional benefits on top of those identified in the SCBA are also discussed.

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Abstract

This paper quantifies the benefits of introducing reactive power markets that promote the participation of distributed energy resources (DER) in a coordinated way, between the electricity system operator and the electricity distribution utilities. The contribution that DER could make by displacing conventional network assets in supplying reactive power support is evaluated in the context of a case study, the Power Potential (PP) project in Great Britain. We discuss the rising need for absorptive (leading) reactive power in the PP trial area, driven by the rapid connection of renewable generation in an area of low demand growth. A social cost benefit analysis (SCBA) is performed to quantify the net benefits, with sensitivities regarding bid prices, % of DER participation, time horizons. Price information from the PP live trial conducted between January and March 2021 is also used to evaluate the robustness of the SCBA and to estimate benefits using actual prices. Our results suggest that energy consumers could save from 8-21% of business as usual asset costs by 2050. The introduction of trial bid prices increases these savings by around 3% of business as usual asset costs out to 2050. Potential sources of additional benefits on top of those identified in the SCBA are also discussed.

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1. Introduction

Voltage levels on the electricity system can be affected by high or low levels of reactive power flow. Reactive power is one type of ancillary services which is usually required by system operators to keep the system voltage within appropriate limits, see NGESO (2021b) for a short background on reactive power. Costs associated to reactive power are socialised among users, in comparison with active power which is seen as tradable commodity (Purchala et al., 2005). Load usually absorb reactive power (Kundur, 1994). In situations of low demand there is an excess of reactive power in the system and voltages increase, meaning that reactive power must be absorbed. On the other hand, in a situation of heavy load (demand) the system consumes reactive power which then needs to be generated to support the system voltage. Reactive power requirements not only depend on demand level but on the configuration of the transmission system and generation (Kirby and Hirst, 1997). Different types of interventions can help with this, including generator actions and network assets for reactive power (Zhong et al. 2008; Frias et al., 2008).

The transition to a low-carbon energy system brings further challenges due to decarbonisation targets that encourage the addition of more intermittent generation (i.e. wind power) in the energy system and changes in the electricity demand profile. These require more and enhanced interventions by both electricity system operators and distribution utilities to keep the system balanced. These interventions need to consider different aspects NGESO (2021a). Considering the locational nature of reactive power, resources need to be procured close to the site where they are needed, meaning distributed energy resources (DER) can play an important role. The adaptation of most-effective solutions that help to maximise consumer benefits is also important, voltage service costs are increasing, and this is expected to continue in the coming years. In addition, ways to increase more participation and greater competition is needed; lack of liquidity and participation is still an issue but DER can help to improve the spatial distribution of reactive resources in the system. Then there is a need to explore and evaluate further options to procure reactive power, which is the motivation for this paper[3].

The current literature about reactive power is diverse, for a brief classification see Anaya and Pollitt (2020). Here we focus on those that explore competitive reactive power markets, optimal use of reactive power support from network assets (e.g. capacitors, others), use of DER in the provision of reactive power and joint active and reactive power markets.

A localised competitive market for reactive power with uniform price auction is discussed in Zhong et al. (2004). The authors propose separated voltage-control areas based on electrical distance and find that this approach not only helps system operators to reduce procurement costs (gross payment to generators is minimised) but also gaming (impact of gaming is restricted in one area). Frias et al. (2008) explore a reactive power market with long term contracts between the system operator and reactive power providers including network assets (e.g. capacitors, shunt reactors). Different types of costs are identified and weighted, including those associated to system contingencies. Li et al. (2006) evaluate the economic benefits of contracting reactive power from local providers such as distributed generators (DGs). They suggest that the economic benefits can be significant when comparing these with capacity payments made to central generators or in the form of power factor penalties applied to power utilities by transmission companies or system operators. A day-ahead reactive power market using two different types of pricing mechanisms is analysed in Amjady et al. (2010). In this study, generators expected payments (with four components of offer prices) are simulated. They find that payments to generators are lower when pay-as-bid is used instead of pay-as-clear. A day-ahead reactive power market is discussed in Rabiee et al. (2009) with the consideration of system security aspects as an extra objective function (in addition to the economical one) in the clearing process. Weighting factors for system security and bid prices are recommended to reflect the priorities of the system operators.

The optimal placement of reactive power equipment in transmission to reduce total power losses is evaluated in Gavasheli and Le Anh Tuan (2007). Results from the cost benefit analysis suggest positive net benefits in most of the simulations. A competitive approach for reactive power dispatch using Pareto efficient transactions is discussed in Biswas et al. (2016). The authors find that social welfare is maximised when a combination of var[4] compensators (capacitors) and superconducting magnetic energy storage (SMES) are taking into account rather than a singular capacitor. Larger power loss reduction and economic benefits are identified. A different study

[3] This paper is based on a study that the authors performed in 2018 for National Grid ESO under the context of Power Potential innovation project in Great Britain. It has been updated accordingly considering the results of the live trial conducted between January-March 2021 (NGESO, 2021b).

[4] Reactive power is measured in units of vol-ampere reactive (var).

evaluates the use of reactive power equipment (such as distribution static compensators: D-STATCOM) in optimal locations and with optimal ratings (Gupta and Kumar, 2019). The authors find important reductions in real and reactive power losses. The simultaneous reconfiguration and allocation of D-STATCOMs in combination with solar PV arrays is evaluated in Tolabi et al. (2015), suggesting important improvements in voltage profile and power losses.

The provision of reactive power support to the distribution network by DGs is analysed in Braun (2008). The author highlights the need of considering the costs of losses in the economic optimisation of network operation resulting from reactive power supply (in the form of self-consumption to provide reactive power). The benefits of using self-adapting reactive power capabilities of DER for solving voltage constraints are estimated by De Alvaro Garcia et al. (2017). They find that the introduction of a dead-band on reactive power regulation increases the DER reactive power capability. This helps to solve voltage constraints and to connect DER at lower costs (reduction of c. 100k€/MW), without reinforcing the network. Gandhi et al. (2020) stress the role of DER in the provision of reactive power support and propose an innovative and cost-efficient solution to control reactive power dispatch. They suggest a local approach (in light of an increasing number of DER) rather than the conventional centralised or distributed ones.

Joint active and reactive markets have been also analysed in some studies. The consideration of a joint active and reactive power market at distribution level is evaluated in Zubo et al. (2018). They suggest a method to maximise social welfare with the integration of demand response. Ahmadi and Foroud (2014) explore a two-step joint day-ahead market (active/reactive power and active/reactive power reserve capacity) at transmission. The authors find that in comparison with traditional independent markets, this approach brings larger reduction in energy not supplied, better incentives to generators to produce reactive power and lower market costs (due to merged markets).

The economics of procuring reactive power from DER using a market-based mechanism needs to be explored further in the current literature. Many of current studies use optimisation methods and estimated payment functions in their analysis. The procurement of reactive power by system operators from DER using a competitive mechanism is something relatively new (Anaya and Pollitt, 2021), then actual market data is limited. The aim of this study is to produce a social cost-benefit analysis (SCBA) to quantify the benefits of introducing reactive power markets that promote the participation of DER in a coordinated way, between the electricity system operator and the electricity distribution utilities. The SCBA involves three different scenarios: Business-As-Usual (BAU) - scenario (S1) - which consists in matching the gap between reactive power system requirements and existing reactive power capability by acquiring network assets for reactive power, specifically static synchronous compensators (STATCOMs). The other two scenarios, scenario 2 (S2) and scenario 3 (S3), involve a more competitive approach with the provision of reactive power support from DER and potential additional resources from the distribution network.

The analysis is done in the context of Power Potential (PP) innovation project. This project is a first of a kind initiative in Great Britain (funded under the Network Innovation Competition run by the energy regulator, Ofgem) that promotes the use of DER in the provision of reactive power support to the transmission system operated by National Grid. PP seeks to procure reactive power from DER located in the distribution network operated by UK Power Networks (UKPN)[5] in day-ahead market with pay as bid pricing mechanism. Due to the locational nature of reactive power support in contrast with active power, pay as bid seems to be a more efficient approach for reactive power market (Amjady et al., 2010). PP considers the contribution DER could make (by displacing conventional network assets) in supplying reactive power support [6] to a specific area in the South of England (part of the Southern Power Network (SPN) service area owned by UK Power Networks) in combination with the current approach (which consists of both a planning and an operational approach to reactive power provision, see Section 2 for details). This area involves four Grid Supply Points (GSPs) where transmission network capacity is limited by voltage stability and the available thermal capacity. This is line with Zhong et al. (2008), where a localised reactive power market is proposed. At these GSPs the voltage steps down from 400kV to 132kV. The future situation that we are studying for the four GSPs is one where the peak requirements for reactive power are assumed to be driven by situations of low demand and high generation from DG, leading to excess reactive power (and high voltage). In this case equipment must be adjusted to absorb reactive power, or

[5] The qualifying DER are those over 1 MW. They are connected at 11 kV or above.
[6] The provision of active power is also within PP; however this study looks only at reactive power.

switched out of service, reducing the flow of generation. This inability to expand or fully utilise available generation because of transmission constraint problems has driven the interest in PP.

Price information from the PP live trial conducted between January and March 2021 is used to evaluate the robustness of the SCBA and to estimate benefits using actual prices. For more details on the PP project and a discussion of theory and evidence on reactive power procurement from around the world see Anaya and Pollitt (2020).

The structure of the paper is as follows. Section two explains the current methods for reactive power management and procurement in Great Britain and introduce the PP project as an innovative and competitive approach to procure reactive power from DER. Section three discusses the SCBA methodology as well as the scenarios, cases and sensitivity analysis. Section four provides details about the data collection and the main assumptions. Sections five explains the reactive power requirements and availability in the PP region. Section six discusses the results of the SCBA. Section seven briefly explains the results of the PP live trial, evaluates the robustness of the SCBA, and extends the empirical analysis by incorporating actual pricing information from the live trial. Section eight concludes.

2. Reactive Power Procurement in Great Britain

2.1 Current methods

There are different ways in which the system operator in Great Britain, National Grid Electricity System Operator (NGESO), can deal with reactive power issues, the planning and operational approaches.

The aim of the *planning approach* is to determine the most economical pattern of new network assets for reactive power (Li, et al., 2005). This involves investment decisions such as the acquisition of shunt reactors/capacitors, static VAR compensators (SVCs), STATCOMs, etc.[7]) in line with the recommendations provided in the Network Options Assessment (NOA) publication[8]. These kinds of equipment are cost effective and have provided historically the majority of NG baseload reactive power (NG, 2018b). These assets are connected to the transmission system (and owned and operated by National Grid Electricity Transmission – NGET) and funded via the transmission network use of system (TNUoS) charges which are split between generators and suppliers as users of the transmission system. The decision to invest in new assets for reactive power support occurs when the NGESO identifies insufficient capability to maintain the voltage levels within the appropriate limits under specific scenarios or through economic assessment using BID3[9], identifying the build solution as the most cost efficient one. The NOA publication (NG, 2018a), released by the NGESO, recommends the kind of investments that transmission owners across Great Britain need to make in agreement with the future network requirements identified by NGESO in their Future Energy Scenarios (FES)[10]. These are only recommendations and it is ultimately the responsibility of the transmission owners to decide on what to invest. In terms of investment in network assets for reactive power supply (i.e. STATCOMs), the most recent NOA publications (2016/17, 2017/18) have identified the need for extra reactive power compensation in the Southeast Coast area and in Bolney and Ninfield (two of the GSPs that are within the PP trial area).

Once the new assets have been acquired the next step is to make use of their ability to supply reactive power support, this refers to the *operational approach*. This involves a set of steps that NGESO takes to meet reactive power needs in real time utilising these kinds of assets. These start with the cheapest available sources of reactive power at the point of dispatch such as adjusting/configuring existing network assets for reactive power (if they are available) and other intermediate operations. It then involves the procurement of reactive power support from third party providers such as transmission connected generators, under three different mechanisms explained below. This is mainly funded by the Balancing Service Use of System (BSUoS) charge. Here we have three schemes, the Obligatory Reactive Power Service (ORPS), the Enhanced Reactive Power Service (ERPS) and constraint management. Under the Grid Code generators are required to produce or absorb reactive power as instructed by the System Operator, generators are compensated using the ORPS methodology

[7] SVC and STATCOM are specific types of Flexible Alternating Current Transmission Systems (FACTS) that can provide dynamic reactive compensation.

[8] See: https://www.nationalgrideso.com/research-publications/network-options-assessment-noa ESO

[9] BID3 is an economic dispatch utilisation model. For further details see Pöyry and NG (2017).

[10] FES comprises four scenarios: Two degrees, Slow progression, Steady state and Consumer power.

outlined in the Connection and Use of System Code (CUSC). ORPS generators are required to produce or absorb reactive power in order to keep the system voltage within appropriate limits, in agreement with the Grid Code requirements.

Generators receive a fixed rate (utilisation rate) in this case (around £2.8/ Mvarh, averaged over the last 5 years), see Table 1 below. ERPS refers to a more competitive scheme, a six-monthly procurement round and is appropriate for generators that can provide reactive power support beyond the Grid Code requirements and also for those who wished to be paid at a rate different from ORPS. NGESO has not contracted for this service since October 2009 and has not received any responses to tenders since January 2011. As of March 2021, this ancillary services product was still theoretically available. For further details about the two mechanisms, see Anaya and Pollitt (2020). The procurement of reactive power via constraint management involves tenders or bilateral contracts between NGESO and individual providers in particular locations (like a single large generator in a constrained part of the network). According to NGESO the most recent voltage constraint contracts have been tendered for. However, contracts with generators in constrained parts of the network are often not subject to direct competition and can be expensive. Finally, actions to procure reactive power can also be taken via the balancing mechanism (which is used by the system operator) to match energy supply and demand in real time), whereby parties are paid to change their real power positions to meet reactive power requirements.

Table 1 shows the payments made to generators under the ORPS scheme and voltage constraint management in the last five years in a specific region that comprises a total of 38 GSPs, including the four GSPs that are part of PP. Constraint costs are around £8.14/Mvarh on average per year with a peak of £13.7 Mvarh in 2013/14, while under the ORPS scheme the annual average costs is around £2.8/Mvarh. It is also noted that leading reactive power utilisation is much more significant under the ORPS scheme, representing around 83.3% of the total contracted capacity via this scheme. Recent figures (period Oct. 2020-Feb. 2021) indicate that leading reactive power is still more usually required, with around 80% over the total[11].

Table 1: Reactive power costs under the ORPS and voltage constraint management scheme at 38 GSPs in the area that includes the 4 GSPs

Scheme	2013/14	2014/15	2015/16	2016/17	2017/18
Mandatory					
total costs £(m)	6.33	5.63	5.31	7.65	5.39
Lead (%)	83.4%	84.4%	82.0%	85.2%	80.9%
utilisation (Mvarh)	2,121,596	2,089,260	2,003,812	2,737,748	1,867,694
Lead (%)	83.6%	84.7%	81.9%	85.0%	81.4%
average cost (£/Mvarh)	2.98	2.69	2.65	2.80	2.89
Constraint					
total costs £(m)	1.05	5.57	0.73	2.22	2.82
capability (Mvarh)	76,733	631,552	119,005	359,396	474,274
average cost (£/Mvar/h)	13.7	8.8	6.1	6.2	5.9

Source: National Grid

2.2 Power Potential: An innovative way to procure reactive power from DER

Power Potential represents a new and coordinated way of procuring reactive power services using DER capability. This procurement is coordinated between the electricity system operator (NGESO) and the electricity distribution utility (UK Power Networks). DER can help to displace or defer the acquisition of dedicated network assets for reactive power by introducing additional Mvars in the system. This may have a positive impact by reducing or deferring investments in network assets for reactive power supply. This translates into lower TNUoS charges, paid by demand and generators. The economic characteristics of procurement from DER versus from network assets differ significantly. One of the advantages of using DER capability is that it is divisible (a smaller

[11] See: https://data.nationalgrideso.com/ancillary-services/obligatory-reactive-power-service-orps-utilisation/r/reactive_utilisation-feb-2021

amount of Mvars from DER can be contracted in contrast with a much larger amount of Mvars from transmission assets, such as those in units of 200 Mvar). The other advantage is that it can be incrementally procured and paid for, unlike transmission assets which must be procured ahead of full utilisation.

In addition, the advantage of procuring reactive power from DER (in comparison to other sources) is that their spatial distribution can increase their effectiveness in providing reactive power. DER can also be better located to deal with other issues that occur periodically. The disadvantage is that even if prices (i.e. availability, utilisation) are low, Mvars do not travel well and decay with distance. Thus, DER effectiveness in reactive power support matters. The size of their compensation needs to be aligned with their merit in the system reactive power support (Amjady et al., 2010). On the other hand, network assets for reactive power connected at transmission can be better located to increase effectiveness and they may be more reliable and cheaper in the longer term. Network assets for reactive power are dedicated to reactive power and hence not in competition with generation[12] (and indeed do not rely on base load generation to be available) which must be running to be capable for providing variable reactive power (with some exceptions such as batteries, overnight solar or units operating in synchronous condensor mode[13]). Varying the type of network assets for reactive power in the mix has further controllability advantages over given mixes of generation. The disadvantage is that these assets are indivisible and can only be added in minimum block sizes (which are quite large, of the order 200 Mvar capacity).

A particular economic feature of these available options is that fixed network assets for reactive power are likely to be more economic if they are expected to be fully and regularly utilised[14], while reactive power from DER is going to be particularly useful in delaying the need for incremental additions of reactive power asset capability, especially in conditions of rising/volatile demand for reactive power. The other situation when DER can be more cost effective, in comparison with network assets, is in periods with high reactive requirements but low expected utilisation. It is also important to note that in line with the connection agreements, DER have to deliver Mvar without affecting the output (MW) at no/little marginal cost but always subject to their effectiveness and to bid prices (in comparison with the fixed rates paid to generators under the ORPS scheme) if a market-based mechanism is used, which is the case in PP. In our CBA, we particularly focus on this use of DER to delay the need to make incremental investments in conventional reactive power assets, relative to a BAU projection of reactive power demand and investments in reactive power assets. Other potential benefits, which are beyond this study, could include the displacement of transmission level generators by DER in the supply of reactive power support (when some DER are cheaper than the transmission connected generators).

3. Social Cost-Benefit Analysis and Scenarios

The social cost benefit analysis (SCBA) focuses on the calculation of the Net Present Value (NPV) of the difference between the BAU and alternative scenarios. We use the social time preference rate (STPR) defined in the HM Treasure Green Book (HM Treasury 2020) to discount all the annual costs across the scenarios.[15] The pre-tax weighted average cost of capital (WACC) is used to convert the required capital cost (i.e. acquisition of STATCOMs in this case) into annual costs over the economic life of the asset (i.e. 45 years). The next step is to discount these annual values using the STPR. The baseline assumption in all the scenarios is that the acquisition of additional network assets for reactive power, reactive power support from DER and from other sources (network optimisation) come after considering the existing reactive power sources which include transmission connected generators, embedded generators over 100 MW, network assets for reactive power and interconnectors (see Section 6.2 for further details). The SCBA evaluates the benefit of migrating from the

[12] An expansion and clarification to this statement is the fact that even although there is currently no direct competition, the decision to procure reactive power is made considering market costs.

[13] Refers to the reactive power capability (generation or absorption) when the generating unit is not producing active energy (Anaya and Pollitt, 2020).

[14] The average current utilisation rate is around 70% according to National Grid.

[15] We have used deliberately the term social CBA (SCBA) in this study because we do use the social interest rate specified in UK government's 'Green Book' (HM Treasury, 2020) which guides government project appraisal, even though we have not considered specific other societal costs and benefits (e.g. power losses, CO2 emissions, others). The inclusion of these variables is beyond the scope of this study but could be considered in future studies.

current system (based on reactive asset investment decisions and operational mechanisms described above) to one which includes an element of competitive procurement.

We have assumed that the demand for leading reactive power drives the reactive power requirements at our four GSPs (in line with Table 1). Thus, only the leading capability of the different reactive power sources has been included in the CBA. The future situation that we are studying for the four GSPs is one where peak requirements for reactive power are driven by situations of low demand and high generation from DG, leading to excess reactive power (and high voltage). In this case equipment must be adjusted to absorb reactive power, or switched out of service, reducing the flow of generation. This inability to expand or fully utilise available generation because of transmission constraint problems has driven the interest in the case study evaluated in this paper, Power Potential.

Our SCBA draws on the original SCBA methodology undertaken for the PP bid in 2016 to the Network Innovation Competition (NG-UK Power Networks, 2016), however it is a new and independent analysis undertaken. In contrast with the prior one, this SCBA looks at the whole reactive power system requirements and potential sources of reactive power supply within the PP trial area. In addition, we incorporate updated information in the light of the outturn competitive procurement (live trial), see Section 7 for details.

CBA of DER projects is of great interest globally, and we undertake an analysis which reflects best practice in this area. EPRI in the US (EPRI, 2015) and the Advanced Energy Economy Institute (Woolf et al., 2014) have published or commissioned helpful guides to undertaking CBA in the context of DER. Our methodology is in line with these and draws on our previous published cost benefit analyses on the connection of distributed generation (Anaya and Pollitt, 2015) and on electrical energy storage (Sidhu et al., 2018). As in our previous papers, the NPV smart energy solutions from the perspective of the electricity system as a whole is evaluated, rather than any single private party to the system.

3.1 About the SCBA methodology

The estimation of benefits is given by the difference between the NPV of total costs in S1 (BAU) and those from S2 and S3 for the period 2020-2050 (S1-S2, S1-S3)[16]. The net benefits of S1-S2 and S1-S3 are discussed as Case 1 and Case 2 respectively in Section 6.

The SCBA involves three main costs: reactive power asset costs, operational and capital expenses for the procurement of reactive power and bid costs. S1 costs include the costs of the acquisition of network assets for reactive power. S2 and S3 costs include the additional bid costs of competitive procurement but lower costs for network assets due to the contribution of additional Mvars by DER and other sources. Network assets are assumed to be repaid (financed) over a 45-year period and also depreciated over the same period and earn the real regulated rate of return on their initial cost and have no running cost[17]. Other expenses in the transmission network have been included in S2 and S3, which amount to £0.03m per year, in line with the former CBA.

In addition, the capital and operational costs for the distribution operator in running reactive power procurement in S2 and S3 need to be considered. The DERMS (Distributed Energy Resources Management System) is the system used to support both the technical and commercial optimisation and dispatch of DER. The capital and operational costs of developing and implementing this new system for the PP trial are covered by the project budget. A large portion of the costs are associated to a trial and would not need to be re-incurred beyond the PP trial. Moreover, the costs of this system would be expected to decrease over time due to the learning process involved in the trial. In addition, economies of scale would apply to a large-scale roll-out, so the cost of implementing the DERMS system would decrease very significantly.

The SCBA in this paper has considered an indicative DERMS cost figure for PP suggested by UK Power Networks. This is equivalent to a capital cost of £0.12m (one-off payment) and an annual operational cost of £0.03m.

Bid costs correspond to the payments made to those DER providing reactive power with winning bids. Bid costs are composed of bid prices (availability and utilisation) payable to DER.

[16] The assumption of 45 years is in line with the new TO asset lives set by Ofgem under RIIO-T2 (Ofgem, 2019, p.6).

[17] Since the repayment period goes beyond 2050 and DER projections are limited to 2050 (data provided by UK Power Networks), we considered convenient to limit the SCBA time horizon to 2050.

The time frame for the analysis is up to 2050 with the evaluation of intermediary years (e.g. 2030, 2040). All the values are discounted back to 2018.

3.2 Scenarios

The CBA involves three scenarios and two cases:

a. ***Scenario 1*** – business-as-usual- (S1), where the supply of reactive power support in case of Mvar capacity shortage is through the acquisition of new network assets for reactive power only. In this scenario, the acquisition of assets comes after considering all of the different existing and available reactive power sources mentioned previously. New assets are represented by STATCOMs only, with capacity increments of 200 Mvar. Price assumptions are in line with the average prices from National Grid's Electricity Ten Year Statement (ETYS), which amount to £24.4m for STATCOMs (based on ETYS average price, 200 Mvar), connected to the transmission network (NG, 2015). No other costs have been included in the estimation of the NPV for this scenario. Even though the provision of reactive power support from transmission connected generators, embedded generators over 100 MW and interconnectors imply a cost (these are getting paid under the ORPS scheme), when comparing the NPV of S1 versus S2 and S1 versus S3, all these costs are common to all scenarios. This means we do not need to calculate them in order to generate our Case 1 and Case 2 results.

b. ***Scenario 2 (S2)***, where participation of DER in the provision of reactive power support is allowed using a market-based approach. This allows the displacement of STATCOMs (reducing the number of additional network assets needed for reactive power) by DER but using an optimal selection of both resources explained in Section 7.2. The use of DER also increases the costs due to the compensation given to DER (via the bid prices: for both availability and utilisation) and additional PP operational expenses (at transmission and distribution levels).

c. ***Scenario 3 (S3)***, similar to (S2), with DER providing reactive power, including the potential additional contribution of extra Mvars from optimising the operation of distribution networks assets (setting of tap changing transformers, reactive compensators, network reconfiguration). The CBA evaluates the value from this additional benefit, assuming zero additional costs to enable that optimisation. This is an important assumption made in this study, in line with Strbac et al. (2018). However, it may be that there are some additional costs for the DNO of releasing this capability. The size of these extra Mvars (leading) is 185 Mvar[18]. We assume these 'free' Mvars arise from the focus in PP on better utilisation of distributed assets in addressing voltage problems at the transmission level. Table 2 summarises the three scenarios.

Table 2: Summary of Scenarios

Scenario	Mvars from New reactive power assets (TO)	Mvars from DER	Mvars for network optimisation	Elements that provide RP support and to take into account in each scenario	Cost figures considered in the CBA
S1	✓			Mvars from: T-connected generators, interconnectors, existing RP assets, new RP assets	new RP assets
S2	✓	✓		Mvars from: All the above plus DER	new RP assets , bid prices (availability, utilisation)
S3	✓	✓	✓	Mvars from: All the above plus network optimisation	new RP assets , bid prices (availability, utilisation)

Note: RP assets include only STATCOMS.

In Case 1 we compare the NPV of S1 and S2. This case captures the benefits of displacing assets by contracting more DER for reactive power support. In Case 2, we compare the NPV of S1 and S3. The following table describes the sensitivities including the central case and the range of values analysed for each one and discussed in the CBA.

[18] We assume free Mvars from Bolney (75 Mvar), Ninfield (60 Mvar) and Sellindge (50 Mvar). See Strbac et al. (2018), Section 3.

Table 3: Summary Table of Sensitivities covered in the CBA

Sensitivities	Central Case	Range of values analysed
Percentage of DER participation	75%	25, 50, 75, 100%
Availability price	£1.5/Mvar/h	0, 0.5, 1, 1.5, 2, 2.5, 3, 4
Utilisation price	£7/Mvarh	0, 4, 7 , 10, 13, 15
NPV (time horizons)	2050	2030, 2040, 2050

Results from Case 1 and Case 2 are then compared with those discounted savings estimated using the outcome competitive information from the live trial in Section 7.

4. Data Collection and Assumptions

Data have been provided by National Grid and UK Power Networks, collected from National Grid's Electricity Ten Year Statement (ETYS) reports and from different studies. Some assumptions are in agreement with those made in the former CBA performed by Imperial College London (NG-UK Power Networks, 2016). Appendix A summarises the list of variables, their sources and the assumptions made for the SCBA. Table 4 shows the projections[19] for installed capacity (at transmission and distribution), reactive power system requirements and reactive power availability taking into consideration all the existing and identified potential reactive power sources, such as DER[20] and interconnectors.

Table 4 shows the projected increase in transmission and distribution connected generators in the area of interest and the associated peak requirements for reactive power absorption given their connection to the grid. This table further shows the ability of the various sources of reactive power capability to provide those requirements. In the absence of any investment in reactive equipment or in competitive procurement there is a rising gap between the need and the availability.

Table 4: Descriptive Figures at the four GSPs

Description	2020	2030	2040	2050
Installed capacity (MW)	**4,308**	**4,989**	**6,461**	**9,264**
Transmission connected generators	2,375	2,632	3,093	3,998
DER (over 100 MW)	720	720	720	720
DER (below 100 MW) - PP	1,213	1,637	2,648	4,546
RP Need (Mvar) at trans.	**3,389**	**3,892**	**5,236**	**7,349**
Transmission connected generators	2,159	2,393	3,093	3,998
DER (over 100 MW)	458	458	458	458
DER (below 100 MW) - PP	772	1,042	1,685	2,893
RP Availability (Mvar) at trans.	**2,264**	**2,442**	**2,916**	**3,659**
Transmission connected generators	781	865	1,118	1,445
DER (over 100 MW)	158	158	158	158
DER (below 100 MW) - PP	266	359	580	996
Reactive equipment (baseline)	1,060	1,060	1,060	1,060
Interconnectors (Mvar)				
Converter capability (from 3 interconnectors)	999	999	999	999
Network optimisation (Mvar)				
Additional reactive power capacity	185	185	185	185
Gap (RP system requirements and available sources)	**59**	**(267)**	**(1,136)**	**(2,505)**

Note: For RP availability it is assumed a participation of 100% from DER and lead capability only (@0.95 PF).
Network assets for reactive power includes SVC and reactors. The gap includes the network optimisation.
Source: UK Power Networks (2018), NG (2017, Appendix A and B), NG (2015, Appendix F).

[19] 2020 figures refer to projections made in our former SCBA study (submitted to National Grid ESO in Dec. 2018), no updates were made.
[20] Here it is assumed that DER have the capability to provide reactive power support and that can be controlled via DERMS (this implies the installation of appropriate equipment).

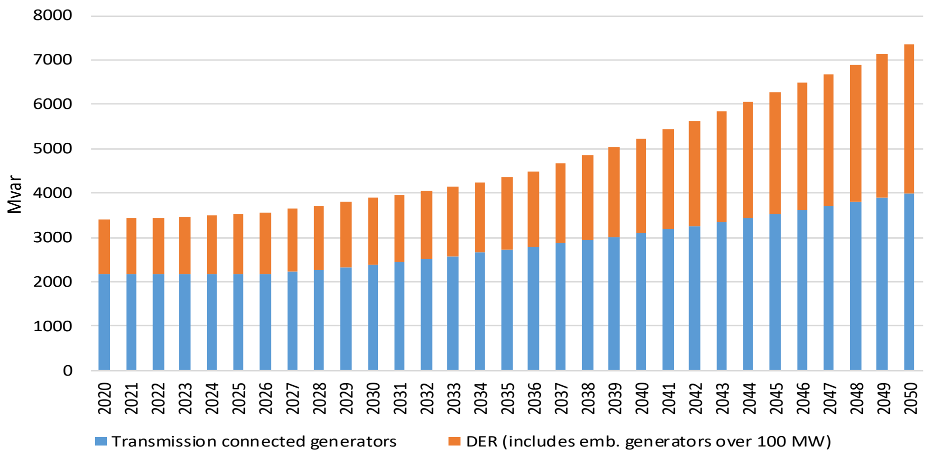
5. Reactive Power System Requirements and Availability

5.1 Reactive Power System Requirements

Reactive power requirements are estimated as set out below for both transmission connected generators and DER. Information about the transmission connected generators was obtained from the ETYS (NG, 2015; NG, 2017). The list of transmission connected generators included in the analysis are those that operate within the zones B1, C4, C7, C9, comprising the four GSPs, and also one generator (London Array) from C3 (connected in Cleve Hill) due to its proximity to the Canterbury North GSP, see ETYS 2017, Appendix A, Fig. A5 in NG (2017). Projections about the size of transmission connected generators are based on those made in ETYS 2015 (NG, 2015), with a fixed installed capacity until 2026. After this year an annual growth rate of 2.6% was taken for doing the projections until 2050[21]. Cumulative projected DER installed capacity (2020-2050) were provided by UK Power Networks[22].

With the installed capacity projections (for both transmission and distribution) we proceed to estimate the reactive power system requirements at the transmission level. Based on National Grid's dynamic voltage analysis in the Southeast area, it is assumed that for 1 GW of transmission capacity required, a total of 900 Mvar is needed at the transmission level, see the Transmission and Distribution Interface 2.0 (TDI) bid document (NG-UK Power Networks, 2016, p.22). In addition, the required capacity at the transmission level due to the connection of DER units takes into account the coincidence factor (e.g. an increase of 10 MW in DG requires an increase of 7 MW at transmission (10 MW * (CF=70%) = 7 MW). The same value of CF has been assumed over the whole period. Figure 1 depicts the reactive power system requirements for transmission connected generators and DER for the period 2020-2050. We observe that the requirement is slightly larger for transmission connected generators than for DER.

Figure 1: Reactive power system requirements at transmission (due to generation connected at transmission and distribution networks)



[21] We do expect some increase in transmission connected generating capacity after 2026: an annual increase of 2.6% after this year. This rate was estimated based on the average annual growth of installed capacity according to ETYS 2013 (Annex F, Table F2.2), see NG (2013). This assumption is also aligned with the compound annual growth rate of transmission-connected capacity for the period 2020-2050 from FES 2020 (leading the way scenario, estimated at 2.6%), see NGESO (2020, SV.25). https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents

[22] These are the same projections as used in the previous CBA in 2016. The compound annual growth rates of installed decentralised capacity for the period 2020-2050 from FES (Leading the way and Consumer Transformation scenarios) are also aligned with the annual rate estimated here from DER projections (around 4.5%). In addition, projections from Distribution Future Energy Scenarios 2020 from UK Power Networks for SPN regarding distributed generation and battery storage, suggest compound annual growth rates of 4.4% and 3.7% for consumer transformation and leading the way scenarios respectively (period 2019-2050), see UK Power Networks (2020).

5.2 Reactive Power Availability

Reactive power availability refers to the existing and potential sources of reactive power support. If there are not enough anticipated sources of reactive power, then investments in network assets for reactive power are required (i.e. purchase of STATCOMs). Existing and potential sources of reactive power include STATCOMs and SVCs, generators (transmission connected and distributed generation), and interconnectors among other things. Only reactive power provided by DER is assumed to be acquired through a competitive mechanism (i.e. bids) in line with PP. In the calculation of the available sources of reactive power support, the current and future capacitive/reactive equipment have been considered according with the ETYS reports (Appendix B, System Data). Reactive equipment figures remain the same for the whole period, which means no projections have been made in addition to the ones already estimated by National Grid (based on the latest figures from ETYS 2017), see NG (2017), Appendix B, Table B.4.1c (current) and Table B.4.2c (additions). The idea is to potentially cover, any shortage of Mvar with other more competitive methods. It is important to note that the current costs of reactive equipment including expected additions have not been included in the SCBA (National Grid has already planned to make these investments in the ETYS regardless of PP and has already committed costs to them).

Reactive power support from generators has been estimated assuming a power factor of 0.95[23]. This is a simplification – noting that the DERMS approach removes power factor restrictions and allows each DER to operate within a defined 'PQ' operational envelope i.e. with a permitted Mvar range at each level of active power MW output. Transmission connected and embedded generators (above 50 MW) are ruled by the Grid Code. These generators are required to have the capability to provide reactive power service and are paid under the ORPS scheme and cannot be part of PP. In the estimation of the Mvar supported by DER, a dV/dQ sensitivity of 1.5 has been considered in line with MPE (2016), which means that for 1.5 Mvar at distribution only 1 Mvar is compensated at transmission.

Interconnectors using modern technology are another source of reactive power support (NG, 2016). Interconnectors can be based on Voltage Source Converter (VSC)-HDVC or Line Commuted Converters (LCC)-HDVC technology. The VSC converter has the capability to absorb and/or generate both active and reactive power without the acquisition of additional equipment, in contrast with LCC converters (SKM, 2013). There are three interconnectors (ElecLink, Nemo and IFA2) with VSC-HDVC technology that are placed inside the four GSPs' region. Table 5 shows all the interconnectors that are inside the four GSPs' region, including IFA (1) which does operate using LCC-HDVC. According to National Grid, the converters placed at each end have a capability range of +/-0.95 PF. Even though there is no single market framework in place for interconnectors yet (which would facilitate the provision of different ancillary services), the three interconnectors are required to provide reactive power support in line with their connection agreements. The interconnectors can be instructed for pre-fault voltage support and get paid via the mandatory ORPS price (similar to a transmission connected generator). We assume that the interconnectors have the same size (1 GW) and can contribute up to +/- 333 Mvar each.

Table 1: Interconnector Characteristics

Name	Developers	Connected to	Technology	DC Voltage (kV)	Power (MW)	Commissioning date	Transmission Length (km)	Cap and Floor Regime	Manufacturers
IFA (1)	NGIH and RTE	France	LCC - HDVC	270	2000	1986	70	No	GEC, Alcatel, BICC, Pirelli
ElecLink	Star Capital Partners Limited and Groupe Eurotunnel	France	VSC-HDVC	320	1000	2019	69	No (merchant basis)	Siemens, Prysmian
Nemo	NGIH and Elia	Belgium	VSC-HDVC	400	1000	2019	141	Yes	Siemens/J-Power System
IFA (2)	NGIH and RTE	France	VSC-HDVC	320	1000	2020	240	Yes	ABB, Prysmian

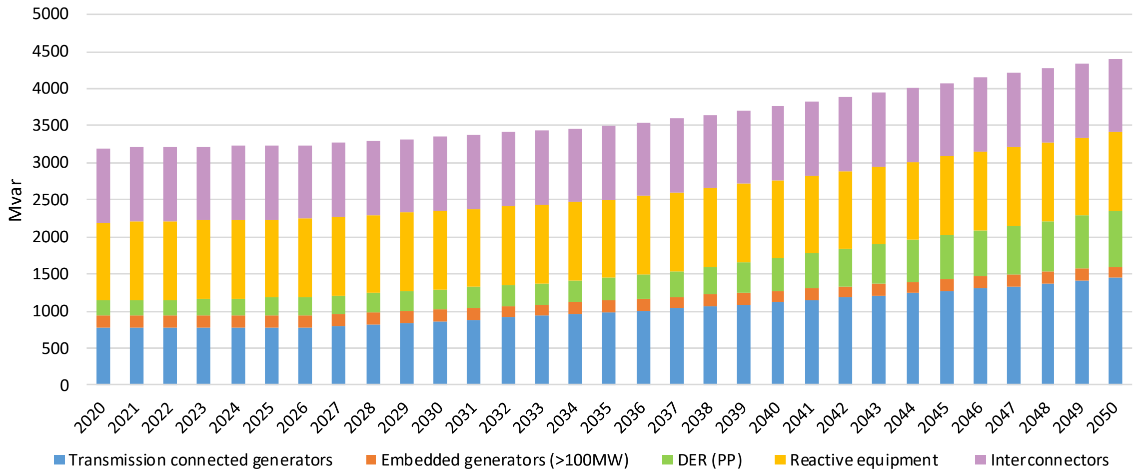
Source: Ofgem website (Interconnectors), Interconnectors website, NG (2016), Barnes (2017).

Figure 2 summarises the different sources of reactive power support across the four GSPs. A quick comparison between this figure and Figure 1, indicates that there is a shortage of Mvars (even with 100% DER participation

[23] For simplicity we have assumed the same power factors across all type of generators. However, we acknowledge that synchronous and non-synchronous generators are subject to different power factors for lagging (0.85 and 0.95 respectively), see https://www.nationalgrideso.com/balancing-services/reactive-power-services/obligatory-reactive-power-service-orps?technical-requirements.

in the provision of reactive power). This shows that, based on the assumptions made, DER alone cannot solve the reactive problem (that they partly create). Thus, we still require more network assets for reactive power (or other potential sources of reactive power support) to match the reactive power system requirements.

Figure 2: Available reactive power support from different sources



Note: It was assumed a 100% of DER participation, only lead reactive capability (for generators, @ 0.95 PF)

5.3 Reactive Power Procurement from DER under PP

In order to conduct the SCBA, we need to put a price on the competitive procurement of reactive power from DER in this analysis (the outturn prices from the PP auction are discussed in Section 8). The price of the competitively procured DER is a key driver of the relative benefit of competitive procurement vs conventional reactive asset investments. However, competitive procurement has the additional advantage that it is divisible (which means that DER capability can be contracted in smaller quantities in line with the capability range) in comparison with traditional network assets for reactive power which must be added in blocks ahead of being utilised at full capacity (i.e. 200 Mvar).

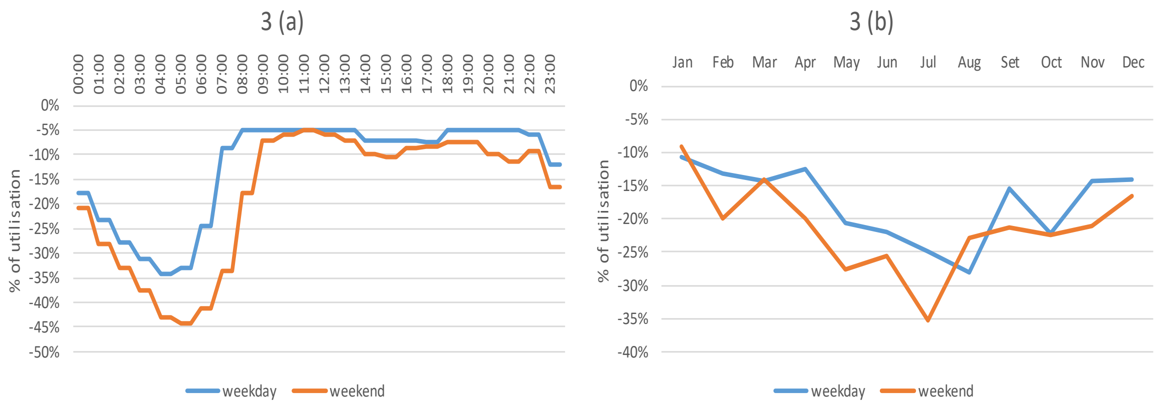
Based on the specifications of PP, the bid price has two components:

- Availability price (£/Mvar/h)
- Utilisation price (£/Mvarh)

For the availability price, it has been assumed that DER are contracted for a minimum of 1800 hours (in agreement with the PP Market Procedures). In the long run, the contracted hours could be reduced, given actual evidence on demand for competitively supplied reactive power and its reliability in meeting demand. The effectiveness of the DER also known as sensitivity value (see NG-UK Power Networks (2018, p. 16)) in the provision of reactive power support is reflected by adding the estimation of both price and the variable "effectiveness". The SCBA looks at average figures of effectiveness, however we are aware this figure can vary across the different generators that take part in the bid. For instance, a generator with an actual availability price of £1.5/Mvar/h and with an effectiveness of 80% at the GSP is equivalent to a delivered availability price of £1.875/Mvar/h (=1.5/0.8) at the GSP. For the estimation of the utilisation cost we have assumed that utilisation is a percentage of the total available hours, set at 19.2% (which means a total of 345 hours). This figure was estimated based on the average lead (-) utilisation profile from transmission connected generators connected within the PP region between April 2016 and April 2018.

Figures 3(a) and 3(b) depict the trend in average utilisation (as a percentage of availability) in the PP region per day (up to 24h) and per month, lead only (with a negative sign due to absorption). As expected, (due to low demand), the utilisation rate is much higher during the period between 1am-7am and during the summer period. Note that reactive power is more required during weekends than in weekdays within day and across the year.

Figure 3: Trend of average utilisation profile of reactive power in the PP region (period April 2016-April 2018)



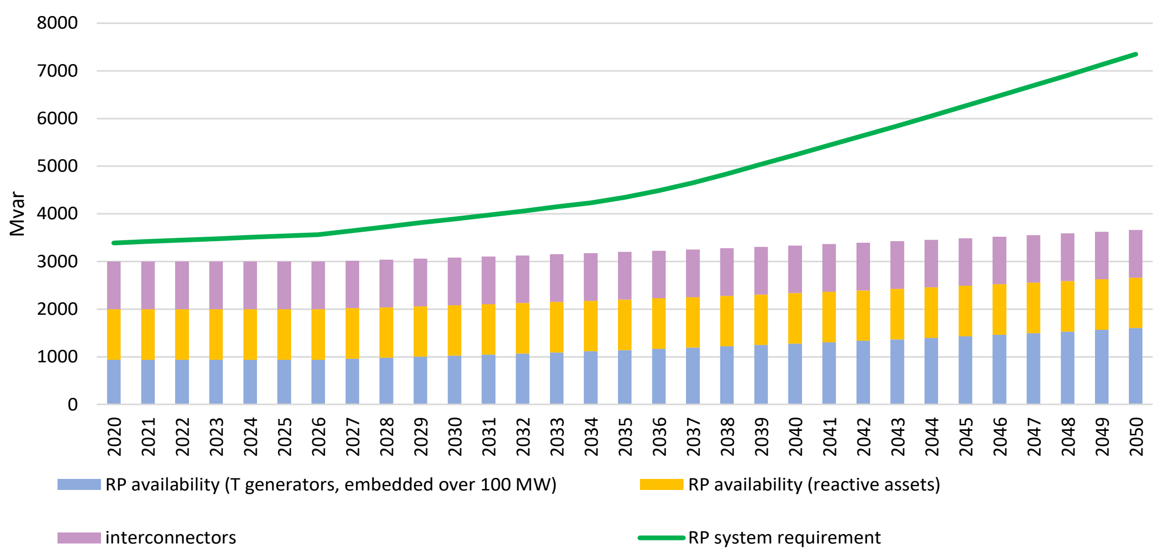
Source: National Grid (historic utilisation profile of RP in the PP region). Exclude bank holidays.

6. Results and Discussion

6.1 The Business-As-Usual approach (S1)

In the BAU approach the solution is to buy the required assets in order to match the anticipated shortage of Mvars for the period 2020-2050[24]. Figure 4 shows that there is a clear shortage even with reactive power support from different sources (transmission connected generators, embedded generators over 100 MW, reactive assets, and interconnectors). The extra reactive power capacity is covered by the acquisition of STATCOMs (19 units with a total capacity of 3,800 Mvar over the period 2020-2050).

Figure 4: Reactive power system requirement versus baseline availability



The participation of DER in the provision of reactive power support can also help to match the existing gap between reactive power system requirements and availability. The reduced investment in reactive assets due to the use of DER, and potential additional reactive power network optimisation at distribution, look like a more cost-effective approach (when comparing their respective NPVs). Thus, two specific cases are discussed in this

[24] In order to avoid any shortage of Mvars in a specific year, the acquisition of the asset(s) is made in the previous year. This applies in both Case 1 and Case 2.

section, Case 1 and Case 2 which compare alternatives options for providing the necessary reactive power capability.

6.2 Case 1 (S1-S2)

In this case, DER supports reactive power, reducing or delaying the requirements to purchase STATCOMs. The exercise is done using four different rates of DER participation (25%, 50%, 75%, 100%). Table 6 shows the results for the three time horizons and the central case (with an availability price of £1.5/Mvar/h and utilisation price of £7/Mvarh).

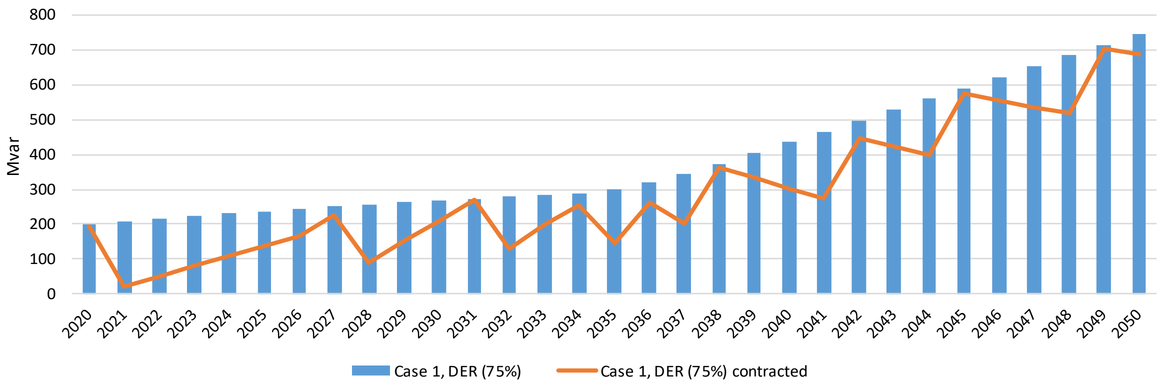
Table 6: Benefits for the Case 1 with central case for DER prices

year	% DER Participation 25% (£m)	50% (£m)	75% (£m)	100% (£m)
2030	3.8	6.2	7.4	7.6
2040	6.1	9.8	10.3	11.2
2050	8.1	12.2	13.4	14.3

Note: Based on AP of £1.5/Mvar/h, UP of £7/Mvarh

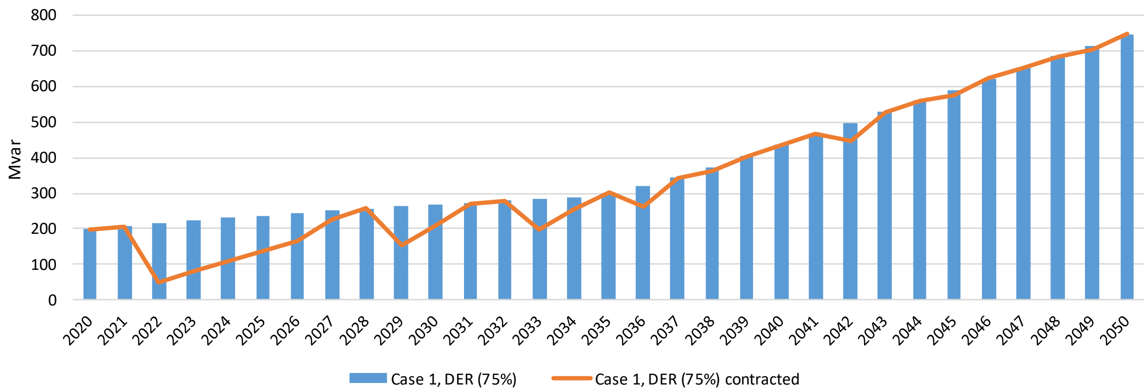
Table 6 shows that there are savings in using an optimal combination of reactive assets and DER reactive power support in comparison with the BAU solution. By 2050 discounted savings amount to £14.3m equivalent to approximately 8% of the cost of BAU solution. We also observe that the benefits are higher when the % of DER participation increases. Benefits reduce to £8.1m by 2050 with a 25% of DER participation. Looking at the number of reactive assets, this decreases when the % of DER participation increases, as expected, with a total of 14 and 18 units required at 100% and 25% of DER participation respectively, compared with the 19 units required under the BAU approach. In terms of the quantity of DER contracted, we observe that especially during the first ten years the full reactive capacity that can be provided by DER is not required. However, after this, there is an increase in contracted reactive capacity from DER with an average value of 83% of the total reactive capacity available during the last ten years. Figure 5 shows the 75% of DER participation case.

Figure 5: Contracted DER versus full DER availability – with smarter selection



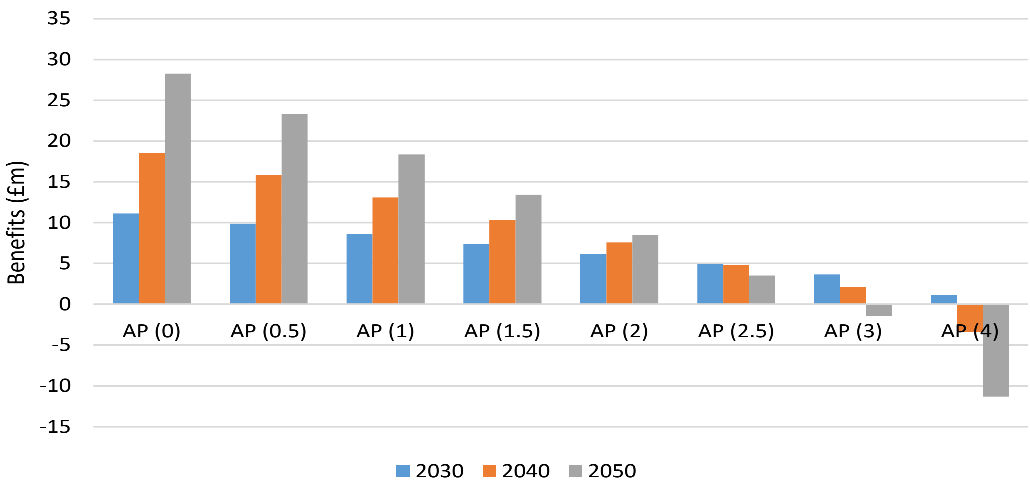
An interesting observation about contracting reactive power capacity from DER is that the order to selecting first DER over the asset, or selecting first the asset over DER or a smarter selection (optimal selection) when the surplus/shortage is zero or close to zero, matters. Figure 6 shows the results of contracting DER reactive power capacity smartly however Figure 6 refers to the first case, contracting DER first and then covering any shortage with STATCOMs. We notice that the trend of contracted reactive power from DER is much smoother. In terms of savings, we observe around £6.3m savings when a smarter selection is applied.

Figure 6: Contracted DER versus full DER availability – DER come first



In terms of prices, the sensitivity analysis shows that, as expected, a change in availability price (AP) produces a major change in the estimated benefits (computed by the difference in the NPVs) in comparison with the utilisation price (UP). Figure 7 shows the benefits of replacing some reactive assets by contracting DER for reactive power support. Benefits are higher with lower availability prices and vary between £28.3m (AP=0) and £3.5m (AP=2.5) by 2050, assuming a fixed value of utilisation price set at £7/Mvarh and 75% of DER participation. However higher values of availability prices do not produce any savings at all by 2050. This means that the BAU option is more cost efficient when availability price exceeds £4/Mvar/h on average.

Figure 7: Sensitivity Analysis for Availability Prices – Case 1 (75% participation of DER)



In terms of the utilisation price, the sensitivity analysis indicates that there are larger benefits from lower prices, see Table 7. A maximum of £26.7m (UP=0) and a minimum of £2m is observed even with a higher value of utilisation price (UP=13) out to 2050, assuming a fixed availability price of £1.5/Mvar/h and 75% of DER participation. However, no savings are observed for utilisation prices that are over £15/Mvarh out to 2050.

Table 7: Sensitivity Analysis for Utilisation Prices – Case 1 (75% participation of DER)

year	Benefits (£m) with different Utilisation price (UP) figures					
	UP (0)	UP(4)	UP(7)	UP(10)	UP(13)	UP (15)
2030	10.7	8.8	7.4	6.0	4.5	3.6
2040	17.7	13.5	10.3	7.2	4.0	1.9
2050	26.7	19.1	13.4	7.7	2.0	-1.7

Note: Based on AP of £1.5/Mvar/h, %DER:75%

6.3 Case 2 (S1-S3)

In this case, some extra Mvars are added, in addition to the ones provided by DER, to help match the reactive power system requirements. The optimisation of the distribution network is estimated to result in the provision of extra Mvars (185 Mvar). This SCBA calculates the higher savings that can be expected in comparison with the previous case assuming no additional costs of releasing this capability[25]. Table 8 shows the results for different rates of DER participation (in agreement with the previous case) assuming an availability price of £1.5/Mvar/h and a utilisation price of £7/Mvarh.

Table 8: Benefits for the central case considering network optimisation

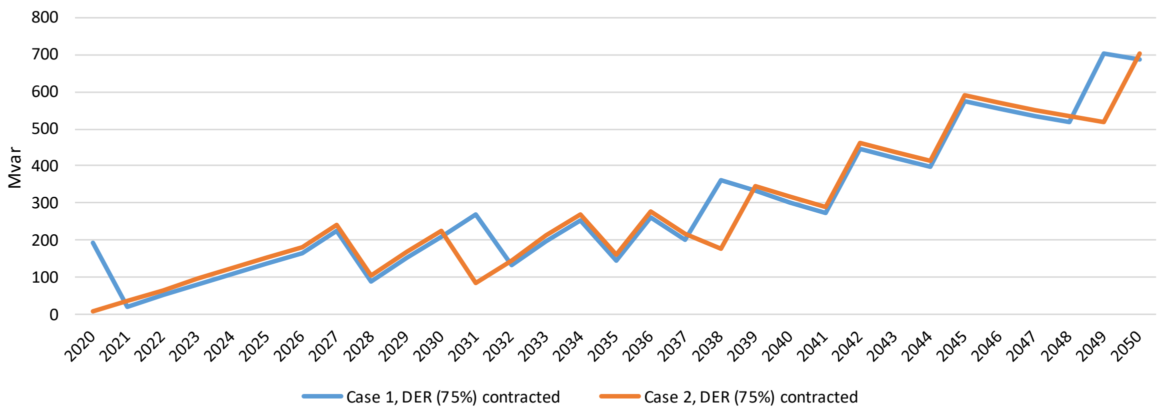
year	% DER Participation			
	25% (£m)	50% (£m)	75% (£m)	100% (£m)
2030	15.9	17.9	18.1	19.1
2040	24.7	28.0	28.3	29.3
2050	31.4	34.7	36.1	37.0

Note: Based on AP of £1.5/Mvar/h, UP of £7/Mvarh

Benefits vary between £31.4m and £37m by 2050. These figures are higher than those in Table 6. This means that the contribution of extra Mvars due to network optimisation, which reduces the amount of contracted DER and the acquisition of extra assets, has an average value of around £23m by 2050[26]. This is equivalent to a further increase of c. 13% of BAU costs. In agreement with Table 6, we also note that benefits are larger with higher % of DER participation. In terms of number of assets, the participation of DER and extra Mvars due to network optimisation reduces the number of reactive assets, with a total of 13 and 17 units required with 100 and 25% of DER participation respectively, compared with the 19 units required under the BAU approach.

In relation to the size of DER contracted, it is observed that the extra Mvars reduce the number of STATCOMs (1 less) for the period 2020-2050, which is reflected by higher benefits in Table 8. Figure 8 illustrates the contracted DER differences between Case 1 and Case 2. It is bigger during the first year, after that a similar trend is observed in both, Case 1 and Case 2, but with specific reductions in 2031, 2038 and 2049, which is explained by the contribution of free Mvars.

Figure 8: Contracted DER under Case 1 and Case 2 (75% participation of DER)

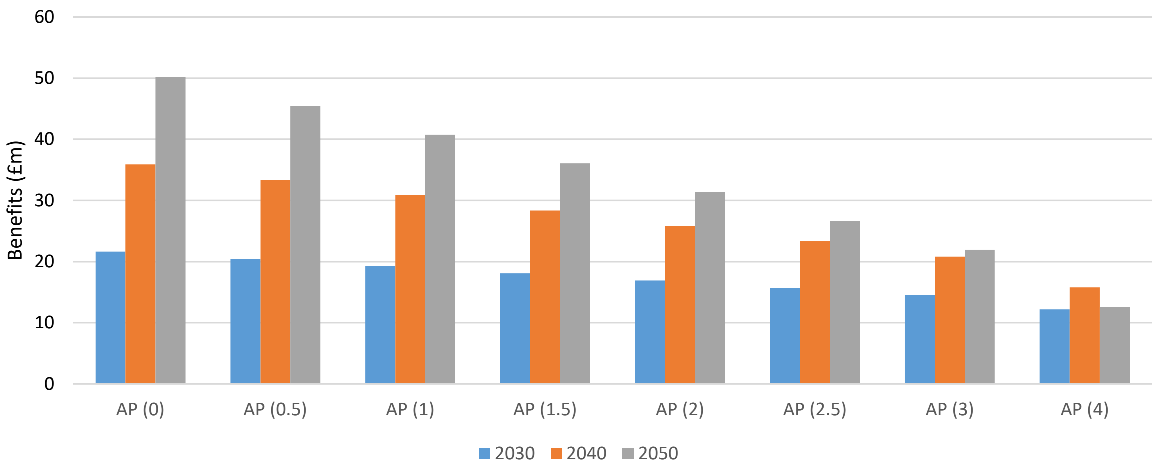


The sensitivity analysis for availability prices shows, as expected, bigger benefits in comparison with Case 1. The lower the prices the bigger the benefits with a maximum and minimum value of £50.2m (AP=0) and £12.5m

[25] A system like DERMS could enhance visibility and monitoring of the distribution network. The additional costs potentially required to enable distribution network optimisation have not been quantified in this SCBA.
[26] Refers to the average of the four % DER participation figures.

(AP=4) out to 2050 respectively, see Figure 9. Benefits drop below zero for availability prices that are over £5.5/Mvar/h out to 2050.

Figure 9: Sensitivity Analysis for Availability Prices – Case 2 (75% participation of DER)



In terms of utilisation prices, the benefits range from £21.6m and £48.7m out to 2050 for the largest (UP=15) and smallest (UP=0) value of utilisation prices respectively, assuming an availability price of £1.5/Mvar/h and 75% of DER participation (see Table 9). However, benefits are not observed for much higher values of utilisation prices. The sensitivity analysis results suggest that for utilisation prices over £27/Mvarh, there are no benefits out to 2050.

Table 9: Sensitivity Analysis for Utilisation Prices – Case 2 (75% participation of DER)

year	Benefits (£m) with different Utilisation price (UP) figures					
	UP (0)	UP(4)	UP(7)	UP(10)	UP(13)	UP (15)
2030	21.2	19.4	18.1	16.7	15.3	14.4
2040	35.1	31.2	28.3	25.4	22.6	20.6
2050	48.7	41.5	36.1	30.6	25.2	21.6

Note: Based on AP of £1.5/Mvar/h, %DER:75%

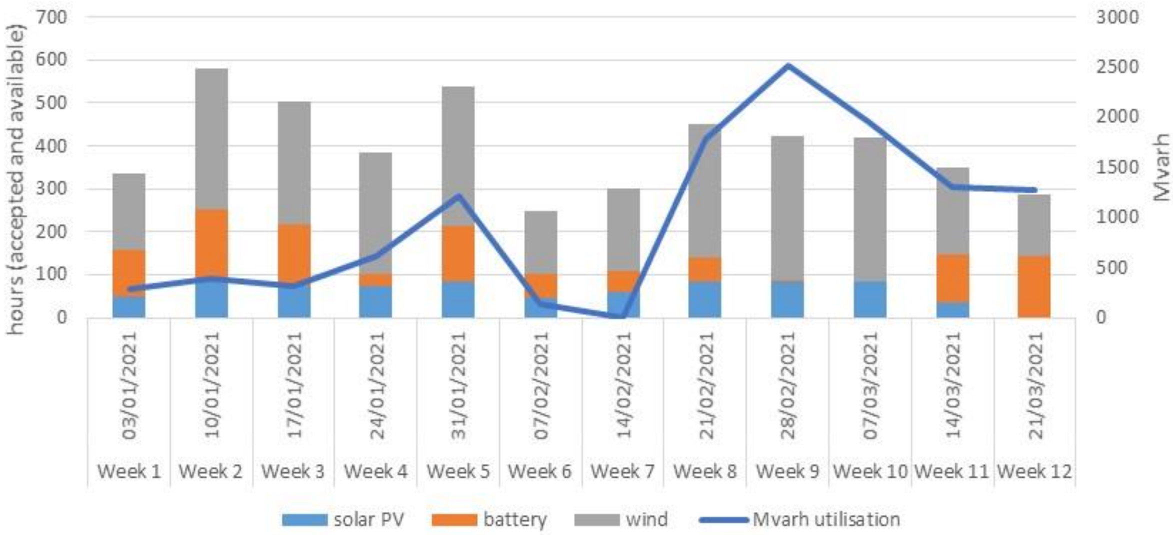
7. Testing the SCBA robustness with live trial results

7.1 About the live trial

This section evaluates the robustness of the SCBA performed in Section 6 using the outcomes of the live trial. The trial started in January 2021 (w.c. on the 3rd of January 2021) for a period of 12 weeks. Bids were submitted from DER located in three GSPs with a combination of bids being received from solar, battery and wind power units. The maximum range of reactive power associated to each DER varies[27], with values from 2 to 39.6 Mvar. Figure 10 depicts the weekly trend of hours (accepted and available) and Mvars utilised (lag and lead combined) per type of technology for 12 weeks. Most of the accepted hours and Mvars utilised are from wind power units (due to their large range of reactive power capacity). In terms of settlement, most of the payments correspond to availability payments, representing around 76% of the total (c. £223k).

[27] The maximum range of reactive power is the sum of maximum lag (+) and maximum lead (-) reactive power capacity declared by each DER.

Figure 10: Hours accepted and Mvars utilised per type of technology in live trial (period Jan.-March. 2021)



7.2 Pricing information, effectiveness and utilisation factors

Estimations of average prices (availability and utilisation), average effectiveness and utilisation factors were required to compute the benefits of procuring reactive power from DER. Weighted average figures were estimated using the maximum range of reactive power associated with each DER. Only prices with an "accepted" production schedule response were considered in the estimation of weighted average prices. No variation was made in the rest of variables.

Results from the analysis suggest average prices for availability and utilisation of £1.46/Mvar/h and £4.80/Mvarh respectively[28], an average effectiveness factor of 74.1% and utilisation factor of 19%. For instance, looking back at Tables 7 and 9 and Figures 7 and 9, we can observe that these prices are within the range of values we originally proposed. An evaluation of absolute maximum and minimum availability and utilisation prices submitted by DER in the live trials suggests that these are also within the suggested range (i.e. with a maximum price of £10/Mvarh for utilisation and £9/Mvar/h for availability). These results add to confidence in our initial assumptions and SCBA estimations.

The following two sections discuss the size of the discounted benefits using actual average prices from the live trial and compare them with the estimates from the central case evaluated in Section 6. An increase in discounted savings is observed when actual average prices and effectiveness factor are introduced. Similar to Section 6, all the figures are in 2018 prices. Average availability and utilisation prices were discounted back to 2018 using the retail price index.

7.3 Case 1 (S1-S2)

Similar to the analysis performed in Section 6.2, benefits are estimated under four rates of DER participation, see Table 10. The use of average weighted prices (availability and utilisation), effectiveness and utilisation factors from the live trial, produces bigger benefits than those computed in Section 6.2 for the central case. For instance, by 2050 discounted savings amount to £19.5m (with DER participation of 100%). This implies an increase of around 36% in comparison with the central case (AP: £1.5/Mvar/h; UP: £7/Mvarh). The average increase of discounted savings across the three time horizons (2030, 2040, 2050) is around 27%.

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[28] Average prices estimated based on data submitted for the whole period (12 weeks).

It is also observed that the results are quite sensitive to the size of the effectiveness factor, estimated at 74.1% from the live trials (average). With no variation of the effectiveness factor (i.e. 80% former value), discounted savings would be bigger on average (i.e. 40.6% higher rather than 21.7%).

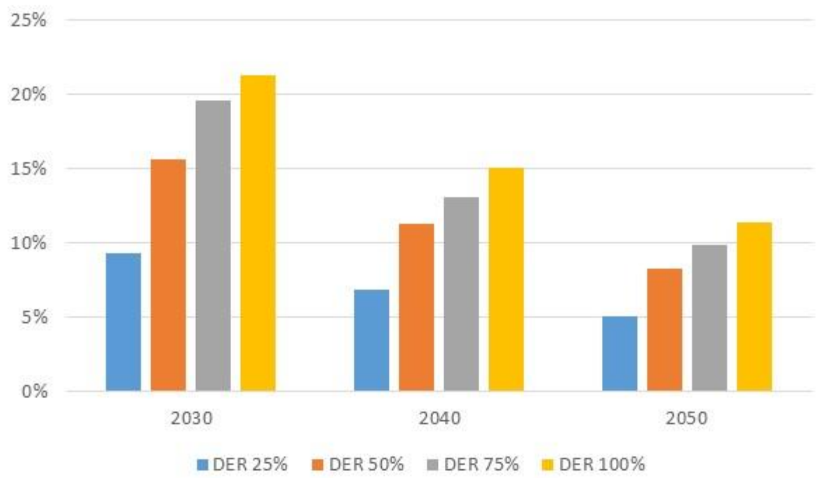
Table 10: Benefits (with prices from live trial)

year	% DER Participation 25% (£m)	50% (£m)	75% (£m)	100% (£m)
2030	3.9	6.6	8.3	9.0
2040	6.4	10.6	12.3	14.2
2050	8.7	14.1	17.0	19.5

Note: Based on AP of £1.46/Mvar/h, UP of £4.80/Mvarh

When comparing with the BAU solution, benefits by 2050 are equivalent to approximately 11% of these costs assuming 100% of DER participation with a peak of 21% by 2030. Figure 11 depicts the percentages for 2030, 2040 and 2050 with different rates of DER participation.

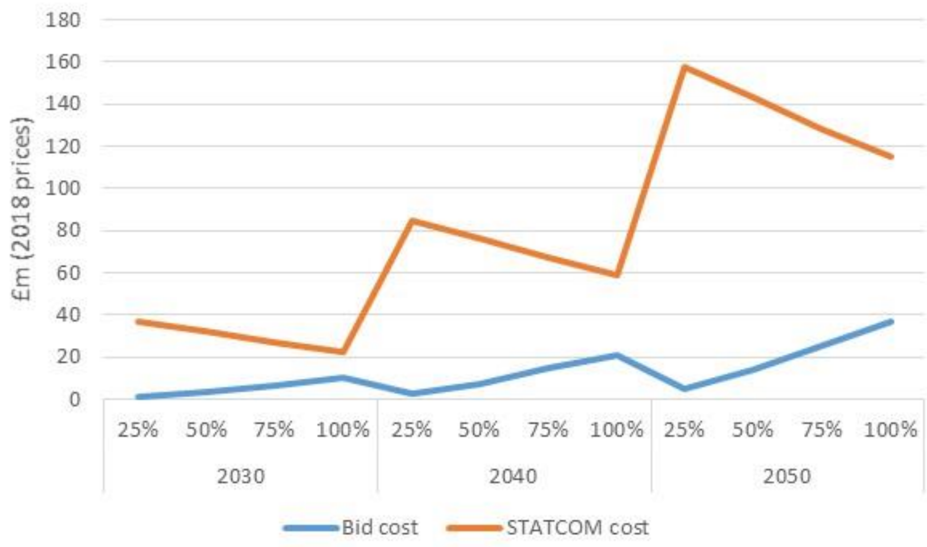
Figure 11: Benefits expressed as % of BAU solution for Case 1 (with prices from live trial)



In terms of costs, by 2050 bid costs[29] represent around 25% of the total costs, assuming 100% of DER participation. As expected, we note that the costs of STATCOMS decrease when the level of DER participation increases, and vice versa in each of the years in evaluation, with a peak of around £157m by 2050 (25% of DER participation). In this case, STATCOMS costs are always higher than bid costs, see Figure 12.

[29] These costs are composed of bid costs (availability and utilisation prices), DERMS costs and PP opex, for details of these costs see Appendix A.

Figure 12: Bid and Stacom costs (NPV) for Case 1 (with prices from live trial)



7.4 Case 2 (S1-S3)

We also consider the value of the extra Mvar due to the optimisation of the distribution network (up to 185 Mvar), which we valued in Section 6.3. As before, the NPV is higher using the actual trial results, see Table 11. A comparison with the central case scenario analysed in Section 6.3 shows that discounted savings by 2050 are 14% higher (assuming 100% DER participation), with an average of around 11% across the three time horizons, considering also 100% of DER participation.

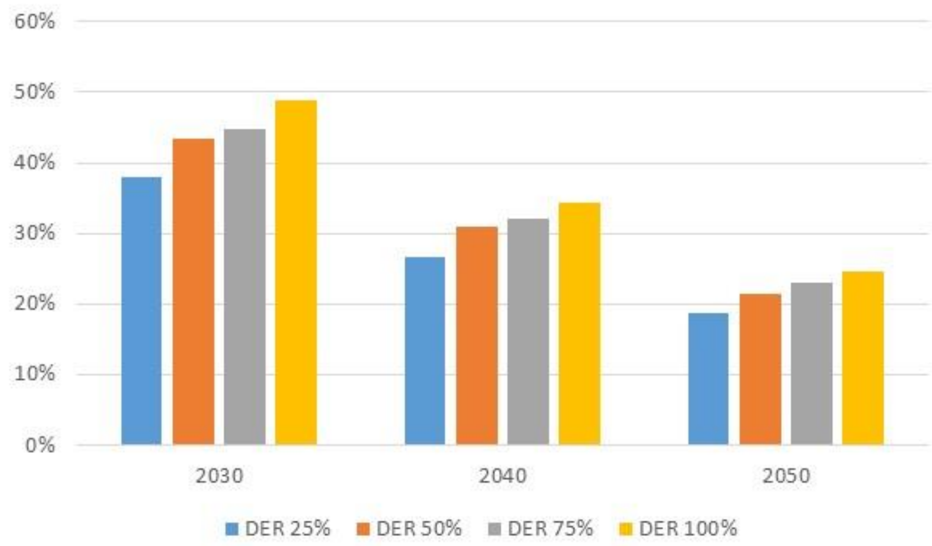
Table 11: Benefits considering network optimisation (with prices from live trial)

year	% DER Participation			
	25% (£m)	50% (£m)	75% (£m)	100% (£m)
2030	16.0	18.4	18.9	20.7
2040	25.0	29.0	30.1	32.3
2050	32.0	36.7	39.4	42.3

Note: Based on AP of £1.46/Mvar/h, UP of £4.80/Mvarh

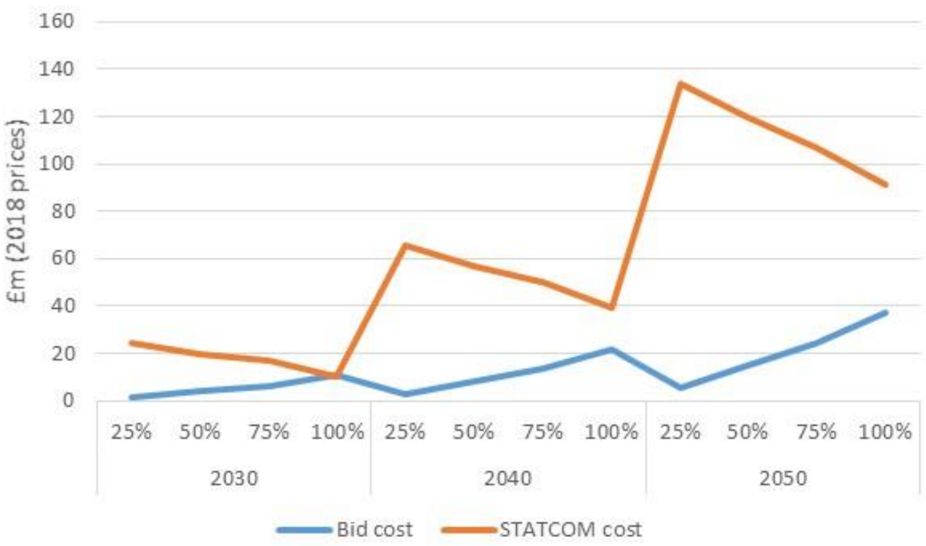
This also results in a saving in cost relative to BAU of approximately 25% by 2050 (with DER participation of 100%), with a peak of around 50% by 2030. Higher levels are expected in comparison with Case 1 because BAU costs are the same for both, but with higher savings in Case 2 due to the addition of extra Mvars (i.e. 185 Mvars). See Figure 13 for further details.

Figure 13: Benefits expressed as % of BAU solution for Case 2 (with prices from live trial)



Looking at the costs, a similar trend to the one in Figure 12 is observed. However, in this case bid costs and the STATCOMS costs would be approximately the same by 2030 with 100% of DER participation (c. £11m), see Figure 14. By 2050 and assuming the same level of participation, bid costs represent around 30% of the total costs. Lower total costs are mainly driven by the reduction in STATCOM costs rather than bid costs, due to the extra Mvars which requires a lower number of STATCOMs. For instance, on average by 2050 and across different levels of DER participation, bid costs are relatively similar in Case 1 and Case 2 but STATCOM costs are around 17% lower in Case 2.

Figure 14: Bid and Stacom costs (NPV) for Case 1 (with prices from live trial)



8. Conclusions

The paper presents a social cost benefit analysis (SCBA) of the competitive procurement of reactive power from DER within the PP area. We work out what the NPV of competitive procurement versus conventional procurement would be, given the costs of conventional reactive assets and the possible market prices from DER offering reactive power. Price information from the PP live trial conducted between January and March 2021 is used to evaluate the robustness of the SCBA and to estimate the net benefits using actual prices. The analysis focuses on leading reactive power where the reactive power needs are driven by the need to increase the capacity to absorb excess Mvars.

This paper models the growing requirement for reactive power arising from low demand-high generation situations on the distribution system, giving rise to the need for additional leading reactive power to absorb excess volts (in the form of Mvars). While transmission connected assets, embedded generators over 100 MW and interconnectors can provide some contribution to the required Mvars at the four GSPs in the trial area, additional absorption capacity is required. If this were to come from DER at reasonable prices this would yield a significant saving in NPV.

Savings from competitive procurement could be of the order of £14.3m in 2018 money (out to 2050, assuming 100% of DER participation). These savings are driven by the deferment of the purchasing of reactive assets which can occur if DER can provide reactive power and represents around 8% of the BAU costs. Given that there are other regions across the country with similar characteristics to the Southeast of England in terms of reactive power requirements, the value of a competitive procurement solution across the whole of Great Britain might be several times larger than the value we calculate. According to NGESO (2021b), savings for energy customers could be over £96m by 2050 if PP is extended in 19 transmission voltage zones (out of 36) with high dynamic voltage requirements, covering around 62% of the number of GSPs in Great Britain; with savings up to around £161m by 2050 if the contribution of DER above 100 MW is included.

The potential value of increased reactive power capability from optimisation by the DNO of their assets is also analysed. This could produce a significant capacity to absorb Mvars given the enhanced focus on reactive power requirements arising from competitive procurement and its associated needs for enhanced modelling, measurement and control within the distribution system. This produces a large additional benefit of the order of £23m in 2018 money (average figure) out to 2050, disregarding the potential costs entailed by such DNO optimisation. This is equivalent to a further increase of c. 13% of BAU costs.

Results from the live trial suggest that the estimated weighted average prices submitted by DER (availability and utilisation) are within the range of prices proposed in the prior SCBA. Higher discounted savings are observed when these prices are incorporated in the analysis. For instance, further increases in NPV equivalent to approximately £5m (c. 3% of BAU costs) is observed by 2050 (at 100% DER participation) in relation to Case 1 and Case 2.

Some sensitivity analysis is also performed. This shows how the procurement price and the availability of competitive procurement influence the NPV. It would also be interesting to carry out additional sensitivity analysis around the cost of reactive power assets, interest rates, WACC or the growth of renewables.

In closing we discuss how competitive procurement might give rise to even larger benefits than the ones we discuss above.

First, if competitive provision also freed up additional thermal capacity for export from the four GSPs that would further enhance the value of Mvar reduction at the GSP. It would do this by reduced DG curtailment or even more connection on the distribution system behind the four GSPs. Either of these would significantly enhance the benefits of the procurement exercise. For instance, if better reactive power management increased thermal capacity by 100 MW for 180 hours in one year in 10 years time, this would add £0.6m to our NPV (at £50/MWh)[30].

Second, more flexible use of DER to provide reactive power can also reduce system losses. To the extent that more reactive power capability in the distribution system leads to better constraint management and that additional thermal transfer capacity reduces the need to thermally stress network assets, this might be an additional benefit from DER participation in reactive power markets.

[30] (£50 * 100 MW * 180 hours) / ((1+0.035)^10).

Third, we might envisage that a long run benefit of competitive procurement from DER is increased innovation in reactive assets that would face direct competition from flexible DER. We have assumed that STATCOMs remain at the same real price and in units of 200 Mvar. If competitive procurement from DER drove innovation in reactive assets, reducing their unit size and unit cost this would be a further benefit of PP.

Fourth, we do only consider leading (not lagging) reactive power. If we were to model competitive procurement of lagging reactive power, there would be some smaller additional benefits arising from situations where the procurement of lagging reactive power from DER was cheaper than other sources. This situation is likely to be much less common than for leading reactive power and the unit savings likely less because they would arise from savings in utilisation payments to transmission connected generators and not in the numbers of reactive assets, which drives our NPV calculation.

Finally, if competitive procurement were extended to transmission connected generators (not just DER) who could provide reactive power, this might significantly reduce the delivered cost of reactive power procurement via the mandatory reactive power market in Great Britain, if the prices were below the current mandatory price level.

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Appendix A: Variables, sources and assumptions

SCBA analysis (Main)

Concept	Value	Sources/Notes
Capacitive/Reactive assets		
Mvar Absorption (ETYS)	1060	From ETYS 2017/2016/2015/2014/2013, appendix B
Reactive power capacity (Mvar)	200	minimum unit
STATCOM costs (£m)	24.4	From ETYS 2015 average figure
STATCOM lifetime (years)	45	Based on RIIO-ET2 (Ofgem, 2019)
DERMS cost (£m)		
Shared costs	0.12	From UK Power Networks
DER Participation Rate		
Percentage of the total Mvars available	75%	Authors' assumption, central case
Estimation of Mvar		
Ratio of distribution and transmission dV/dQ sensitivity	1.5	MPE (2016) (in agreement with former CBA)
Released transmission capacity, MVA (MW) per MVAr	1.1	NG (2016), in agreement with former CBA, for 1 GW around 900Mvar is needed at transmission
Installed capacity		
DER 4 GSP		
current capacity (MW)	1546	UK Power Networks (2018)
Transmission at 4 GSP		
current capacity (MW)	2375	From ETYS 2013 - generation capacity in zones: B1, C4, C7, C9 and in C3 only London Array
Generators' growth rate after 2026	2.60%	From ETYS 2013
Interconnectors (voltage support) - Mvar		
NEMO	333	From National Grid
ElecLink	333	From National Grid
IFA2	333	From National Grid
Network optimisation extra Mvars		
Number of extra Mvars	185.00	From ICL Report (Goran et al., 2018)
PP Bid		
number of hours available	1800	Minimum number of hours required (NG-UK Power Networks, 2018)
availability price (£/Mvar/h)	1.50	Authors' assumption, central case
% utilisation (over total hours available)	19.2%	Average value of utilisation (lead) in the PP region from National Grid
utilisation price (£/Mvarh)	7.00	Authors' assumption, central case
average effectiveness	80%	Authors' assumption
PP Costs (£m), annual		
opex at transmission and distribution	0.03	From UK Power Networks/National Grid
Rates		
TO WACC	4.55%	Based on RIIO-T1 Final Proposal (Ofgem, 2012)
STPR (social time preference rate)	3.50%	Based on Green Book, 3% after the first 30 years (HM Treasury, 2020)

SCBA analysis (Live trial)

Concept	Value	Sources/Notes
PP Bid		
availability price (£/Mvar/h)	1.46	Live trial results
utilisation price (£/Mvarh)	4.80	Live trial results
utilisation factor	19%	Live trial results
average effectiveness	74%	Live trial results