Evaluating the case for introducing locational DUoS charges for CDCM generators

A REPORT PREPARED FOR THE ENERGY NETWORKS ASSOCIATION

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Executive Summary

The Energy Networks Association (ENA) has commissioned Frontier Economics to undertake a comprehensive assessment of the costs and benefits of introducing locational use of system charges for generators that choose to site on the high voltage (HV) and low voltage (LV) tiers of electricity distribution networks. This study builds on preliminary analysis that the ENA published in September 2010[1] and comments subsequently provided by Ofgem, the GB energy industry regulator, in its decision letter of 14 December 2010.[2] Our report does not develop a fully-formed methodology for deriving locational charges for generators. Rather it is our intention that the results of the study could be used to inform the development of future charging methodology proposals for this group of network users.

Charges levied on generators for using the distribution network could, in theory, vary by location and, in so doing, send a financial signal to generators that reflects the costs that they impose on the network by siting at different locations. An often cited benefit of this is that such charges could – in principle – defer the need for network expenditure by discouraging generators from siting in areas where further generation growth could trigger costly reinforcement of the network. The charges could also – in principle – encourage generators to site in areas where growth in demand might trigger the need for further investment in network capacity. In so doing, this might also defer the need for this investment. In turn, by reducing the need for further investment in the network, overall costs to final customers would be lower than would otherwise be the case.

Historically, charges levied on generators for using the electricity network have only varied at the transmission level and the extra-high voltage level of the electricity distribution network, as this is where generation has predominantly connected. However, the likely increase in small-scale renewable generation means that, in the future, there is likely to be considerably more generation siting at the HV and LV levels. Hence, going forward, locational charging might be beneficial at the HV and LV levels if it reduces the need for network investment.

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1 See "*CDCM charging condition report to Ofgem Generation charging in generation dominated areas*", ENA, September 2010:

http://energynetworks.squarespace.com/storage/cdcm/CDCM%20generation%20dominated%20report%2031Aug2010.pdf

2 See Ofgem decision letter, "*Decision in relation to completion of CDCM approval condition – generation dominated areas*", December 2010:

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/Gen%20Dominated%20condition%20decision%201210.pdf

However, these potential benefits need to be weighed against the likely costs of introducing and maintaining a locational generation charging regime at the HV and LV level. In particular:

- distribution network operators (DNOs) would need to devote time and resources to developing an appropriate charging methodology, collecting and updating the necessary data, deriving tariffs and generating invoices for suppliers, amongst other things; and
- suppliers would also be likely to incur certain costs – for example, suppliers' billing costs to final customers might increase if locational charges mean that charging signals had to passed onto generation customers on a highly granular basis.

If these industry set-up costs and ongoing costs were significant and outweighed the benefits of reduced network expenditure by DNOs on account of the locational charges, introducing locational HV and LV generation tariffs could result in higher bills for end customers.

Where possible, we have sought to quantify and compare the potential costs and benefits outlined above. To do this, we consider three high-level options for introducing locational charges, ranging from complex to simple. Our analysis of the costs and benefits of introducing each of these charging options points to the following three key conclusions:

Conclusion 1: there is a strong case against introducing a complex locational charging regime as things stand today. This complex charging regime would send highly granular, cost reflective locational charges (varying from postcode to postcode, for example) to all generators siting at the HV and LV network levels. Our analysis suggests that:

- it would cost more than £250m to introduce and maintain such a charging regime over a ten-year period; and that
- relatively few areas of the GB distribution network are "generation-dominated" in the sense that expected generation growth is likely to trigger thermal reinforcement within the next ten years.

As a result of this, we calculate that the cost of introducing and maintaining such a complex locational charging methodology would only be justified if it succeeded in bringing about an implausibly large change in generation customers' siting behaviour (specifically, it would need to reduce future generation growth in generation-dominated areas by nearly 70%). Having said that, our analysis also suggests that the high cost of the 'complex' option is driven in large part by the high cost of data collection in the absence of smart metering – this suggests that there may be a case for re-examining the 'complex' option when smart metering is fully rolled out (although, even then, there may be other qualitative reasons to reject such an option – as we highlight below).

Conclusion 2: there may be a case for introducing a simpler charging regime whereby DNOs send HV generation customers (but *not* LV generation customers) a broad, less granular locational charge that makes use of their existing data collection and billing systems capabilities. Our analysis suggests that the cost to DNOs and suppliers of introducing and maintaining such a charging regime would sum to just £6.6m over the next ten years. We have calculated that, because of this low cost, such a charging regime would only need to have a modest effect on generation siting decisions to be justified (specifically, a 3% reduction in annual generation growth rates in generation-dominated areas would suffice).

Conclusion 3: careful consideration should also be given to any advantages and disadvantages that are more difficult to quantify. In particular, the industry must consider:

- **whether suppliers would pass on locational charging cost signals to generators** (suppliers may be wary of any development that would further complicate the already-complex system of tariffs that they levy on end customers, particularly given Ofgem's recent warning that customers are currently "bamboozled" by the number of tariffs on offer);
- the potentially negative effect that locational charging could have on the **simplicity, transparency and predictability** of charges (which Ofgem, in our view rightly, cites as relevant charging objectives alongside cost reflectivity); and
- the interaction of locational charges with other energy policies and objectives, including:
  - the risk that the 'complex' option could act as a **barrier to entry and competition in the electricity supply market**; and
  - the risk that, by transferring risk onto generation customers, locational charges could reduce the rate of generation growth even in demand-dominated areas, thereby making it **more difficult for the UK to meet its 2020 renewable energy targets**.

Looking ahead, we suggest the following next steps:

- The DNOs should consider how much weight to place on the 'qualitative' concerns about introducing locational generation charges set out above – as noted, these concerns are inherently difficult to quantify, but they may nonetheless be significant.

- Depending on the conclusions they reach about the significance of these qualitative concerns, the DNOs should then consider whether to implement a locational generation charging methodology along the lines of the 'simple' option outlined above.

- It should also be noted that our analysis only evaluates the costs and benefits of introducing locational generation charges relative to the existing non-locational charging regime. In light of this, the DNOs might also wish to consider whether there may be ways of modifying the existing charging regime to achieve some of the benefits associated with locational charges without actually introducing location-based generation tariffs.

1 Introduction

This report by Frontier Economics has been commissioned by the Energy Networks Association (ENA). It provides an evaluation of the case for introducing location-based charges for generation customers who connect at lower voltage levels of the electricity distribution networks in Great Britain.

Our analysis comes against the backdrop of a wider project to introduce a common distribution charging methodology (CDCM) for high voltage (HV) and low voltage (LV) electricity network users across all 14 distribution network licence areas in GB. Ofgem, the GB energy markets regulator, approved the CDCM in 2009, subject to certain conditions being met.[3] One of these conditions required the regional electricity distribution licensees (known as DNOs) to develop, where appropriate, a charging method that would apply to generators that are covered by the CDCM and are identified as being in generation-dominated areas. Ofgem stressed that, while this did not necessarily mean that generation charges should end up being locational, it was nonetheless "*keen that the DNOs think through the issue and available options … more fully*".

At present, the CDCM offers a p/KWh credit[4] to generation customers, irrespective of where they are located on the network, to reflect the fact that – in general – local generation can reduce the need for costly network reinforcement by offsetting any local growth in demand. However, it is conceivable that there might be some parts of the HV and LV distribution networks where local generation capacity is forecast to grow to the extent that it exceeds local demand load at certain times of year. In these situations, it might be the case that generation triggers network reinforcement rather than preventing it. We understand that it was for this reason that Ofgem required the DNOs to consider how to charge generators in these "generation-dominated" areas.

In September 2010, the ENA, acting on behalf of the DNOs, submitted a preliminary response to this condition placed by Ofgem.[5] The report set out a preliminary analysis of the prevalence of generation-dominated areas and evaluated, at a high level, the costs and benefits that might be associated with a

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3 See Ofgem decision document 140/09, "*Electricity distribution structure of charges: the common distribution charging methodology at lower voltages*", November 2009:

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/CDCM%20decision%20doc%20201109%20(2).pdf

4 In addition to this credit, the CDCM levies a fixed charge (p/MPAN/day) on generators where appropriate. A reactive charge (p/kVArh) is also levied where the charge band is exceeded.

5 See "*CDCM charging condition report to Ofgem Generation charging in generation dominated areas*", ENA, September 2010:

http://energynetworks.squarespace.com/storage/cdcm/CDCM%20generation%20dominated%20report%2031Aug2010.pdf range of different options for introducing locational CDCM generator charges. The report reached the preliminary conclusion that the DNOs should not introduce locational charges for CDCM generators at that time. However, the DNOs also proposed to follow up this preliminary analysis with a more complete study of the issue of tariffs for CDCM generators in generation-dominated areas.

The ENA has commissioned Frontier to undertake this more detailed examination of the costs and benefits associated with different options for introducing locational CDCM generation charges. This study not only builds on both the ENA's preliminary analysis, but also takes account of the observations and reservations about that analysis set out by Ofgem in its decision letter of 14 December 2010.[6] While this report does not itself attempt to develop a fully-formed locational charging methodology for such generators, the results of this study could be used to inform the development of future charging proposals for this group of network users.

We have divided this report into six further chapters.

- In **Chapter 2**, we provide a descriptive overview of the potential costs and benefits of introducing locational charges for CDCM generators. We then set out our analytical framework for evaluating those costs and benefits that can be quantified.

- In **Chapter 3**, we consider how a "generation-dominated area" should be defined. We then use network data supplied by the DNOs to identify how many areas of the GB distribution network are "generation dominated" according to this definition.

- In **Chapter 4**, we provide an overview of the different options for introducing locational charges for CDCM generators. For each of these options, we then seek to quantify the costs that DNOs and suppliers would incur if the DNOs were to introduce and maintain such a charging methodology. Since there is a range of potential options for introducing locational charges, we identify a range of potential costs.

- In **Chapter 5**, we turn to the potential benefits of introducing locational charges. Specifically, we identify the typical network reinforcement cost that might be averted if locational charging signals were to redirect generation growth away from a generation-dominated area.

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6 See Ofgem decision letter, "*Decision in relation to completion of CDCM approval condition – generation dominated areas*", December 2010:

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/Gen%20Dominated%20condition%20decision%201210.pdf

- In **Chapter 6**, we draw the cost-benefit analysis together. Taking account of the number of generation-dominated areas (from Chapter 3) and the potential cost of network reinforcement in such areas (from Chapter 5), we calculate how significant the benefits of introducing locational charges would need to be across all generation-dominated areas in order to justify the costs identified in Chapter 4. We then ask whether it would be plausible to assume that locational charges could bring about such benefits.

- In practice, not all of the costs and benefits of introducing locational charges for generators can easily be quantified. In **Chapter 7**, therefore, we set out and discuss a range of other qualitative considerations that would need to be taken into account when assessing the case for introducing locational CDCM generator charges.

2 Overview of analytical framework for evaluating the case for locational charges

In this chapter, we provide a descriptive overview of the potential costs and benefits of introducing locational charges for CDCM generators. We then set out our proposed framework for quantifying and comparing these costs and benefits where it is possible to do so.

2.1 Our understanding of the potential benefits of introducing locational generation charges

When deciding whether to veto a proposed Distribution Use of System (DUoS) charging methodology, Ofgem's Authority must assess the extent to which these changes would better facilitate the achievement of a number of objectives, as set out in Standard Licence Condition 13A.9 of the electricity distribution licence. This states that DNOs must adopt a charging methodology that "*results in charges which, as far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred … by the licensee in its Distribution Business*".

Ofgem provided further clarification on this principle of "cost reflectivity" in its July 2008 decision on the common methodology for Use of System charges.[7] Ofgem emphasised that one of the key goals of its long-running structure of charges project has been "*to ensure that DNOs provide appropriate incentives to their customers to encourage efficient use of their networks*". To this end, charges should be calculated so as to reflect all significant cost drivers, but they should also be "*forward-looking*". In other words, instead of simply billing customers for the costs that they have historically imposed on the network, charges should seek to send customers a "*price signal*" about the costs that their decisions today could impose on the network in the future. In this way, customers will internalise the costs associated with their actions when making decisions about their use of the distribution network.

We understand that Ofgem's call for DNOs to develop, where appropriate, a distinct charging method that would apply to generators in "generation-dominated areas" was motivated by this wish to ensure that charges are appropriately cost reflective in the sense described above. DUoS charges that are perfectly "cost reflective" in this sense would need to vary from location to

[7] See Ofgem document "Delivering the electricity distribution structure of charges project: decision on a common methodology for use of system charges from April 2010, consultation on the methodology to be applied across DNOs and consultation on governance arrangements", July 2008

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/FINAL%20July%20consultation%20letter_22_07_08.pdf location to the extent that a customer would impose higher costs on the network by siting in one area than by siting in another. For example:

- If new generation capacity were to connect to a part of the distribution network where there was significant local demand but little existing generation capacity, these generators could under some circumstances help to prevent, or at least defer, the need for reinforcement of local network assets by reducing growth in net demand. In this scenario, a cost reflective DUoS charging methodology should offer credits (i.e., negative charges) to generation customers who site in this area, to reflect the fact that they are helping to reduce network investment costs.

- By contrast, if new generation capacity were to connect to a part of the distribution network where there was very little local demand and/or a significant amount of existing generation capacity, the output from these generators could in theory lead to reverse power flows (from low voltage to high voltage) across the local substation. Such reverse flows could in principle trigger, or at least bring forward, the need for reinforcement of local network assets. In such a scenario, a perfectly forward looking cost reflective DUoS charging methodology should charge generation customers who site in this area, to reflect the fact that they are accelerating, rather than reducing, network investment costs.

At present, the CDCM offers a p/KWh credit to all HV and LV generation customers, irrespective of where they are located on the network. This may be an appropriate signal to send to generators in areas where local generation can reduce the need for costly network reinforcement by offsetting any local growth in demand. However, a simple credit will not always be cost reflective and, following the logic set out above, could conceivably send generators the wrong signal altogether on parts of the distribution network where modest growth in generation capacity could trigger costly network reinforcement.

2.2 The potential costs associated with introducing and maintaining locational generation charges

The logic of "cost reflectivity" set out above suggests that there may be a case for introducing DUoS charges for CDCM generators that vary by location if there are many parts of the distribution network where growth in generation capacity could trigger costly network reinforcement. However, as Ofgem has also recognised, these potential benefits need to be weighed against a number of potential costs associated with introducing locational charges for these network users. These potential costs can be grouped into four categories:

- implementation costs for DNOs;

- implementation costs for suppliers;
- the potential loss of simplicity transparency and complexity; and
- potential issues arising from the interaction of locational generation charges with other energy policies and objectives.

We discuss each of these categories of cost in turn below.

Implementation costs for DNOs

Any benefits associated with introducing locational charges for CDCM generators would need to be weighed against the costs of introducing and maintaining a new charging regime for these customers. Standard Licence Condition 13A.9 of the electricity distribution licence explicitly recognises this need to consider these costs when it states that DNOs must adopt a charging methodology that "*results in charges which, **as far as is reasonably practicable after taking account of implementation costs**, reflect the costs incurred … by the licensee in its Distribution Business*". In practice, DNOs would be likely to incur several types of costs if they were to introduce locational charges – for example, costs associated with:

- **Developing the methodology** – the DNOs would need to spend time on developing an appropriate methodology for introducing locational charges to "bolt-on" to the current CDCM methodology;
- **Collecting data** – and, where necessary, updating this data on a periodic basis such that the locational charges remain relatively cost reflective. Collecting data may require additional metering equipment to be installed at substations that fall within the DNOs' asset base as well as additional man hours;
- **Deriving tariffs** – the data would need to be entered into a system or spreadsheet that then calculates the tariffs for different types of generators;
- **Generating invoices** – the tariffs would need to be combined with generation data to calculate the credits or charges that should be levied on individual generators;
- **Sending invoices to suppliers** – the generated invoices would need to be sent to suppliers either electronically or using a paper-based system; and
- **Resolving any disputes with suppliers** – suppliers may have queries about the generation data or the tariff that generators have been placed on.

Implementation costs for suppliers

For locational generation charges to deliver any benefits at all, it is vital that suppliers pass these charging signals directly on to end customers. However, suppliers would themselves be likely to face a range of costs if locational charges were introduced – for example, cost associated with:

- **Verifying that invoices are correct –** the suppliers would need to ensure that the invoices that they receive from the DNOs are correct. This may involve both checking that the generation data is correct and verifying that generators have been placed on the correct tariff;
- **Adding locational generation charges to other charges to calculate bills** – since generation use of system charges will only form one component of a package of credits and charges levied on generators. For example, generators will also receive credits for the electricity that they sell to the network;
- **Sending bills to customers** – either electronically or using a paper-based system; and
- **Dealing with additional queries and complaints from generators** – generators may query the generation data that they use or may question the tariff they have been placed on.

In addition to this, suppliers are currently under pressure to simplify the system of tariffs that they offer to customers. Given this, suppliers are likely to be wary of any development – such as the introduction of locational charges – that would further complicate the already-complex system of tariffs. We consider this issue in more detail in Chapter 7.

Potential loss of simplicity, transparency and predictability

In its May 2005 consultation on the longer term framework for the structure of electricity distribution charges,[8] Ofgem outlined a number of other high-level principles for distribution charges to "sit alongside" the principle of cost reflectivity. Three of these further principles were:

- simplicity;
- transparency; and
- predictability.

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8 See Ofgem document "Structure of electricity distribution charges. Consultation on the longer term charging framework". May 2005

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/10763-13505.pdf

The principles of predictability and transparency are in many ways as important as that of cost reflectivity in facilitating efficient network use. As Ofgem pointed out in its 2005 consultation paper, this is because "*long term [siting] decisions will be based on expectations of future costs, rather than solely on current charges, so it is important that future charges are predictable, as far as possible, and that reasonable expectations are not overturned without good reason.*"

Ofgem reiterated this point in its July 2008 decision on the common methodology for Use of System charges, emphasising that as well as being cost reflective, charges should also "*be transparent and predictable to allow users to estimate future charges*". In the same decision document Ofgem observed, correctly in our view, that there was an "*inevitable tension*" between cost reflectivity on the one hand and simplicity, transparency and predictability on the other. It emphasised that the development of a use of system charging methodology was therefore "*a balancing act between a number of competing principles*". In light of this, any benefits associated with introducing more cost reflective charges must be balanced against the associated drawbacks in the form of increased methodological complexity and reduced transparency and predictability.

Interaction with other energy policies and objectives

Careful attention should be paid to the potential interaction of locational CDCM generation charges with other energy policies, programmes and objectives to make sure that the introduction of such charges would not have any undesirable and unintended consequences in these fields.

One such "unintended consequence" might relate to the dynamics of competition between suppliers. Introducing locational charges could in principle undermine competition between suppliers in more than one way. For example:

- a complex locational charging methodology that, for example, required suppliers to bill customers on an individual basis could potentially require suppliers to invest in expensive new billing systems – and any resulting increase in upfront investment costs could, in principle, constitute a barrier to entry for new suppliers;
- moreover, increasingly complex tariffs could weaken competition between suppliers if they make it more difficult for consumers to compare the products that different suppliers offer.

Any such effects would need careful consideration, not least because the DNOs are required to facilitate competition in the supply of electricity. Indeed, the industry needs to be particularly mindful of this risk, given Ofgem's recent warning[9] that "*competition [between suppliers] is being stifled by a combination of tariff complexity … and lack of transparency*". We discuss this further in Chapter 7,

Attention should also be paid to any effect that locational generation charges could have on the UK's ability to meet its target to source more than 30% of its electricity from renewable sources by 2020.[10] For example, if cost reflective locational generation charges are also volatile and unpredictable, this could deter renewable generation from connecting to the HV/LV network.

2.3 Analytical framework for assessing the case for introducing locational generator charges

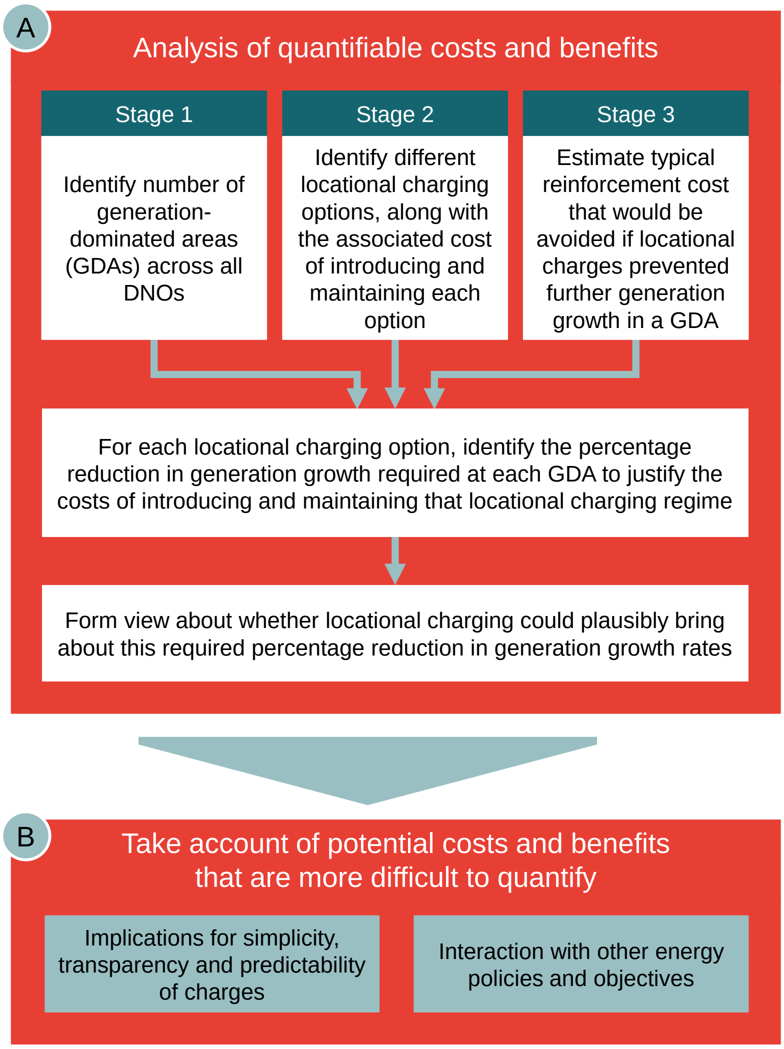
Figure 1 below provides a schematic overview of the analytical framework that we have used to assess the case for introducing locational generator charges.

9 See: http://www.ofgem.gov.uk/Media/PressRel/Documents1/RMRFinal%20Final.pdf

10 See *"The Renewable Energy Strategy",* HM Government, 2009

Overview of analytical framework for evaluating the case for locational charges

Figure 1. Framework for assessing case for introducing locational generator charges



Source: Frontier Economics

As Figure 1 sets out, we have undertaken the following two-part analysis:

- In Part A, we compare those costs and benefits that can be quantified. To facilitate this, we divide the analysis into three stages.

  1. In Stage 1, we set out and discuss our understanding of what constitutes a "**generation-dominated area**" and then identify the number of parts of each DNO network that can be thought of as being generation-dominated using this definition.
  2. In Stage 2, we identify a set of different **options for introducing locational charging** and estimate the associated **cost of introducing and maintaining each option**.

3. In Stage 3, we estimate the **typical reinforcement cost** that would be avoided if locational charges were to prevent further generation growth in a generation-dominated area. This provides a measure of the potential benefits that could result from introducing such charges.

For each locational charging option, we then combine the findings from Stages 1, 2 and 3 to identify the minimum extent to which generation customers would need to change their siting behaviour in response to locational charging signals in order to justify the cost of introducing and maintaining that locational charging regime. We then form a view about whether that locational charging regime could plausibly bring about this minimum required change in siting behaviour.

- In Part B, we take account of further potential costs and benefits that are more difficult to quantify. In particular, we consider:
  - the implications of each of the locational charging options for simplicity, transparency and predictability of charges; and
  - the interaction of locational charges with other energy policies and objectives.

3 Analysis of Generation-dominated areas

In this chapter we set out and discuss our understanding of what constitutes a "generation-dominated area" and then identify the number of parts of each DNO network that can be thought of as being generation-dominated using this definition. Specifically, we:

- discuss possible issues surrounding the definition of a generation-dominated area;
- propose an identification method for generation-dominated areas;
- present results on the forecast evolution and prevalence of generation-dominated areas using this method of identification; and
- evaluate the implications of these results, and the method of identification.

3.1 Issues regarding the definition and identification of a generation-dominated area

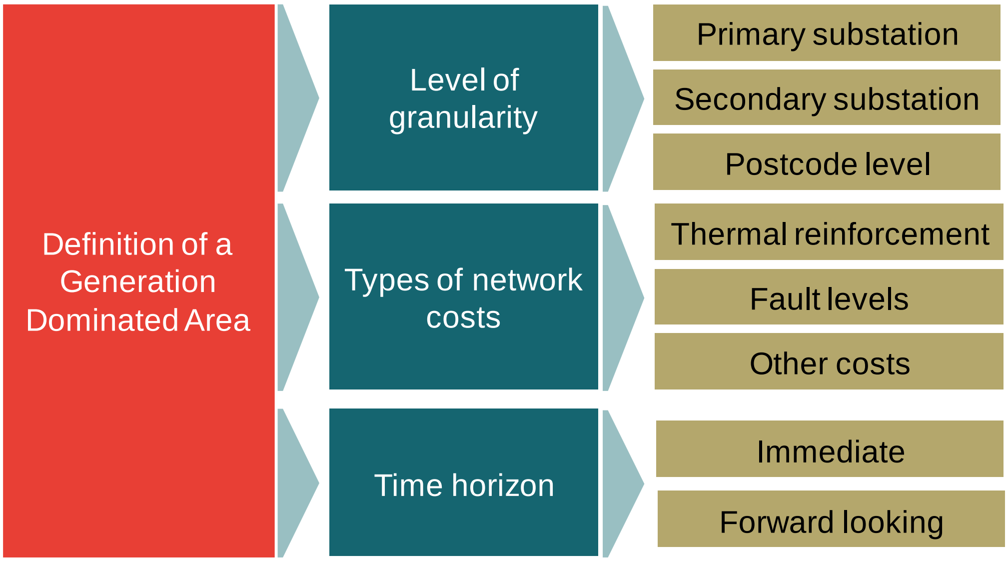
This section provides a discussion of the issues to be considered when attempting to define a generation-dominated area, and proposes a method of identification.

3.1.1 Overview of the different possible definitions of a generation-dominated area

There is no single, universally accepted definition of a generation-dominated area. A generation-dominated area could, for example, be defined as any part of the network where generation capacity exceeds demand at certain times of year. Alternatively, it could be defined more narrowly as a part of the network where generation is forecast to trigger network reinforcement. Different definitions will be suitable in different circumstances, depending on the purpose of the analysis being undertaken.

We have identified three variables that should be considered when attempting to define a generation-dominated area (GDA). These three variables are set out in Figure 2 below.

Figure 2. Overview of the factors to consider when defining a GDA



Source: Frontier Economics

We discuss the three variables outlined in Figure 2 in more detail below:

- **Level of granularity** – this relates to the definition of the "area" of the network that may or may not be generation-dominated. For example, this geographical area could be a set of houses on a street (postcode level), all premises served by a specific distribution substation, or those served by a specific primary substation. In practice, the ability to define the "area" component will be driven by data availability to a significant extent.

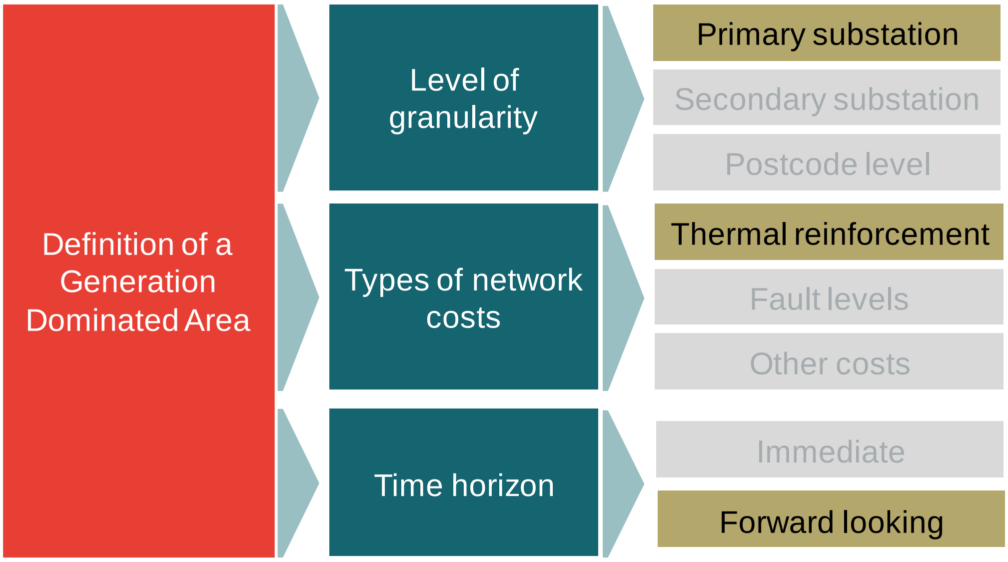
- **Types of network investment costs** – at one level, a GDA could simply be defined as any part of the network where generation capacity exceeds demand at certain times of year; alternatively, the definition could be based on whether or not generation growth ends up creating a need for network-related investment expenditure. With the latter definition, a further issue arises with respect to the *type* of network-related investment expenditure that generation growth creates. Examples of network costs that could theoretically be triggered by both demand and generation activities include thermal reinforcement and fault level related investment.

- **Time horizon** – a definition of a GDA could be either "static" or "forward-looking". The former would only consider network conditions at the current moment in time, whilst the latter would consider how network conditions are likely to evolve in the future. With a forward-looking definition, one could also consider the effect of looking at time horizons, for example ten or twenty years.

3.1.2 Overview of our proposed definition of a generation-dominated area

In this report, we define a generation-dominated area as "*a primary substation where thermal reinforcement is more likely to be caused by generation than demand, within a specific time period*". Figure 3 below sets out where this definition sits in the space of possible definitions set out above.

Figure 3. Factors used to identify a GDA



Source: Frontier Economics

As Figure 3 sets out, our definition of a GDA:

- focuses on primary substations (rather than assets below the primary);
- focuses on whether or not generation growth is likely to trigger network expenditure (rather than simply looking at the balance between demand and generation) and, more specifically, thermal reinforcement (rather than fault level related investment, for example); and
- is forward-looking, in the sense that it identifies whether this thermal reinforcement is likely to occur within a specific time period.

We explain our rationale for adopting this proposed definition of a GDA in Section 3.1.4 below. First, however, in Section 3.1.3 we provide a more detailed overview of the test that we have used to identify GDAs using this definition.

3.1.3 Method for identifying a generation-dominated area using this definition

In order to identify potentially generation-dominated areas on the GB distribution networks using the definition of a GDA set out above, we apply a single test incorporating a number of variable parameters. Specifically, for each primary substation on the GB electricity distribution network, the following test is applied:

Proposed identification test for GDAs

$$FC \times SW < GC_t - [MIND \times (1 + g_{MIND\%})^t]$$

Where

FC is the firm capacity served by the substation, measured in MW.

SW is a factor < 1 reflecting the fact that summer firm capacity is less than winter firm capacity.

GC_t is the total estimated generation capacity on the substation in period t, measured in MW.

$MIND$ is the estimated existing minimum demand served by the primary substation. This is calculated as the product of the observed maximum demand and a minimum demand scaling factor.

$g_{MIND\%}$ is the annual percentage growth rate in the level of minimum demand.

t is the time horizon (n years) over which the test seeks to identify the prevalence of GDAs.

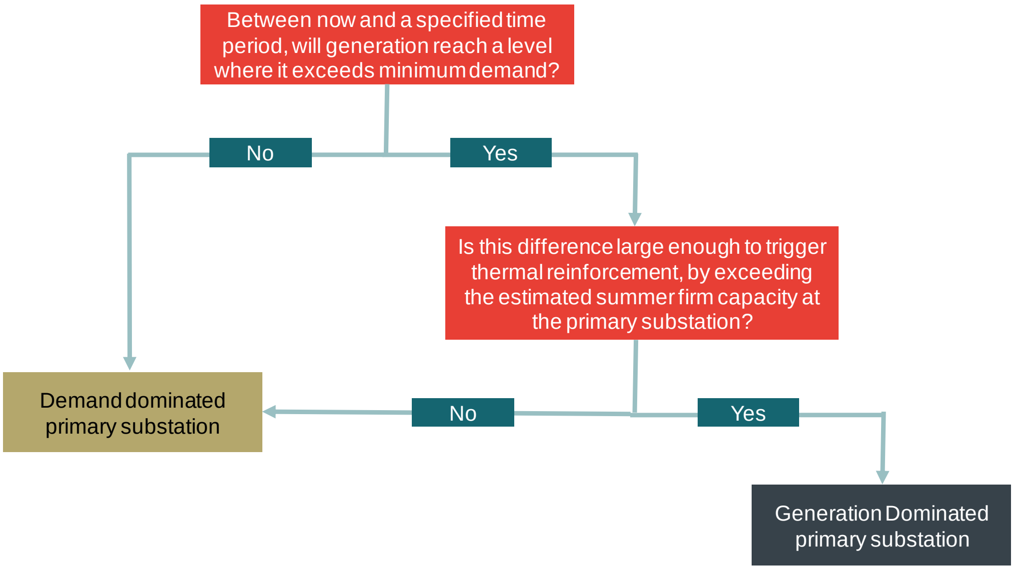
Any primary substation for which the above inequality is true we define as a *generation-dominated area*.

Given a time horizon, t, the above test attempts to identify whether between the current moment in time and the specified time period:

- generation capacity feeding into a primary substation will reach a point where it will exceed the level of minimum demand; and
- the difference between generation capacity and minimum demand is large enough to trigger thermal reinforcement within the specified time period.

This process is set out in Figure 4 below.

Figure 4. Identification test for a GDA



Source: Frontier Economics

We estimate generation capacity in period t (GC_t) by taking the existing generation capacity at each primary substation and assuming that this generation capacity grows at a fixed rate for t years. We consider two alternative scenarios about the pattern of this growth in generation capacity:

- **Percentage growth ("hotspot" scenario)** – under this scenario, generation growth is applied in fixed percentage increments. This means that generation capacity only grows at substations where there is at least some generation capacity to begin with.

- **Absolute growth ("even growth" scenario)** – under this scenario, generation growth is applied in fixed absolute increments. This allows for distributed generation to connect at all substations, *including* those where generation capacity is zero to begin with.

Our analysis therefore considers the following two possible distributed generation growth scenarios:

An overview of the generation growth scenarios

- **"Hot spot growth"** – growth in distributed generation is focussed solely on areas where there is existing distributed generation (DG) capacity (i.e. a percentage growth rate in generation is applied). The identification test under this generation growth scenario is:

$$FC \times SW < [GC \times (1 + g_{DG\%})^t] - [MIND \times (1 + g_{MIND\%})^t]$$

$g_{DG\%}$ is the annual *percentage* growth rate in distributed generation.

- **"Even growth"** – growth in distributed generation is spread evenly across all primary substations, regardless of the existing generation capacity (i.e an absolute growth MW rate in generation is applied). The identification test under this generation growth scenario is:

$$FC \times SW < [GC + (t \times g_{DGAbs})] - [MIND \times (1 + g_{MIND\%})^t]$$

g_{DGAbs} is the annual *absolute* growth in distributed generation, measured in MW per primary substation.

Table 1 below summarises the required input parameters for our method of identification, and their level of granularity.

Table 1. Input parameters for GDA identification

Input Parameter	Symbol	Level of Granularity
Firm capacity	FC	Primary substation
Summer: winter ratio	SW	DNO area
Minimum demand growth	$g_{MIND\%}$	DNO area
Minimum demand	$MIND$	Primary substation
Generation capacity	GC	Primary substation
Generation growth rate	$g_{DG\%}$ and g_{DGAbs}	DNO area
Time horizon	t	All DNO areas

Source: Frontier Economics

3.1.4 Evaluation of our proposed definition and test for a generation-dominated area

In our view, both the definition of a GDA that we proposed in Section 3.1.2 and the test for identifying a GDA that we outlined in Section 3.1.3 are appropriate, given the issues we are investigating, for the following four reasons:

- **Our definition of a GDA is based on a forward-looking assessment of future network investment costs** – in considering whether there is a case to be made for introducing locational CDCM generation charges, we are interested in finding out whether, in the absence of locational charging, generation growth would force DNOs to undertake costly investment in many areas of their networks. Given this objective, our definition of a GDA is appropriate because it identifies those parts of the network where future generation growth, if left unchecked, would be likely to drive costly network investment.

- **Our definition of GDA focuses on the network investment costs that matter most in practice** – we understand from discussions with the DNOs that thermal reinforcement is a significant driver of distribution network investment. DPCR05, for example, forecasts £1.4bn of DNO expenditure on general reinforcement, contrasted with £0.13bn on fault level investment.[11] As such, identifying when generation growth is likely to trigger thermal reinforcement is likely to provide a good indication of when that generation is most likely to trigger network investment.

- **Our test for GDAs is flexible** – in particular, the parameters of our GDA test can all be modified, thereby allowing us to evaluate the sensitivity of the results to different assumptions. Similarly, the test looks at the effect of assuming different *patterns* of generation growth (i.e., "hotspot" growth vis-à-vis evenly distributed growth) as well as different growth *rates*.

- **Our test for GDAs is utilisable in the sense that it makes use of data that is readily available** – extensive data is available on a primary substation level for maximum demand, firm capacity and the amount of distributed generation currently connected. By contrast, there is no power flow data available for distribution substations below the primary level (e.g., distribution substations). To perform analysis at a greater level of granularity would require additional data not currently available.

While we therefore believe that both our proposed definition of a GDA and our proposed test for identifying GDAs are appropriate for the reasons set out

[11] Forecast expenditure on the total network (comprises 132kV/EHV/HV/LV)

above, we have nonetheless identified three potential limitations of our proposed method of identification. These relating to:

- the decision to focus solely on thermal reinforcement costs;
- the level at which GDA identification is performed; and
- considering summer firm capacity only.

Types of network costs

The proposed test only considers a situation where distributed generation triggers *thermal reinforcement* costs. An example of a potentially relevant cost excluded in this identification method, which was identified as a potential issue by Ofgem[12], is fault level investment.

Following discussions with the Distribution Network Operators, however, we do not believe the omission of fault levels to be a serious drawback with our method of identification. In particular:

- fault level investment is not, at present, a significant driver of ongoing network investment when compared to thermal reinforcement (as already noted they comprise less than 10% of total network investment in DPCR05); and
- for the HV level at least, fault-level-related costs are typically identified at the time of connection, and can be reflected and recovered through connection charges as compared to DUoS charges.

In addition to this, we also note that fault-level-related costs are not considered in the current incarnation of the EDCM. Fault level analysis originally played a prominent role in SP's proposed Forward Cost Pricing (FCP) methodology, but that this proposal was subsequently vetoed by Ofgem. In its September 2008 decision letter on SP's proposal[13], Ofgem explained that it considered that it would be *"very difficult for a generator to understand how its charges were calculated from the detail provided in SP's proposed [FCP] methodology statement"* and that SP had *"unnecessarily developed a more complicated and complex methodology for generator charges than they currently have in place."* We understand that Ofgem was, amongst other things,

12 http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/Gen%20Dominated%20condition%20decision%201210.pdf

13 http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/SPM%20Decision%20letter.pdf

concerned about the complexity caused by the original proposed FCP methodology's use of fault analysis to identify DUoS charges. We also understand that the removal of this fault level analysis was one of the factors that may have contributed to Ofgem's decision in July 2009[14] not to veto a modified version of FCP charging methodology for the EDCM. Given this, it would arguably be disproportionate to consider fault-level-related costs as part of analysis pertaining to the CDCM, which is meant to be a less complex and computationally intensive methodology than the EDCM.

Level of granularity

The proposed test only considers the primary substation level, which may not be appropriate if there is a long term goal to introduce a highly granular charging methodology on the HV/LV networks.

Following discussions with DNOs, however, we do not believe this to be a significant oversight for the following reasons:

- LR2 tables suggest that most of the distributed generation that is forecast to connect to the HV/LV network over the coming years will connect at the HV level when measured in terms of the amount of MW capacity connected. These generators will tend to connect close to the primary substation and so are unlikely to trigger reinforcement of assets below the primary; and
- substations below the primary level are generally unmetered, and as such directional power flows are not readily available for analysis. In the event of such data becoming available, analysis would need to be performed on in excess of 450,000 substations and transformers[15] to identify if they were generation dominated. Whilst it might be possible to adopt a sampling approach at this level, the data does not currently exist.

Focusing on summer conditions

Our proposed test only examines the evolution of the relationship between demand and generation in the minimum demand scenario (i.e., it seeks to identify where and when surplus generation in the minimum demand scenario exceeds

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14 See page 31 of Ofgem's decision document of 31 July 2009 for more on the decision to remove fault levels from the FCP analysis

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/July%20decision%20EHV%20charging%20and%20governance.pdf

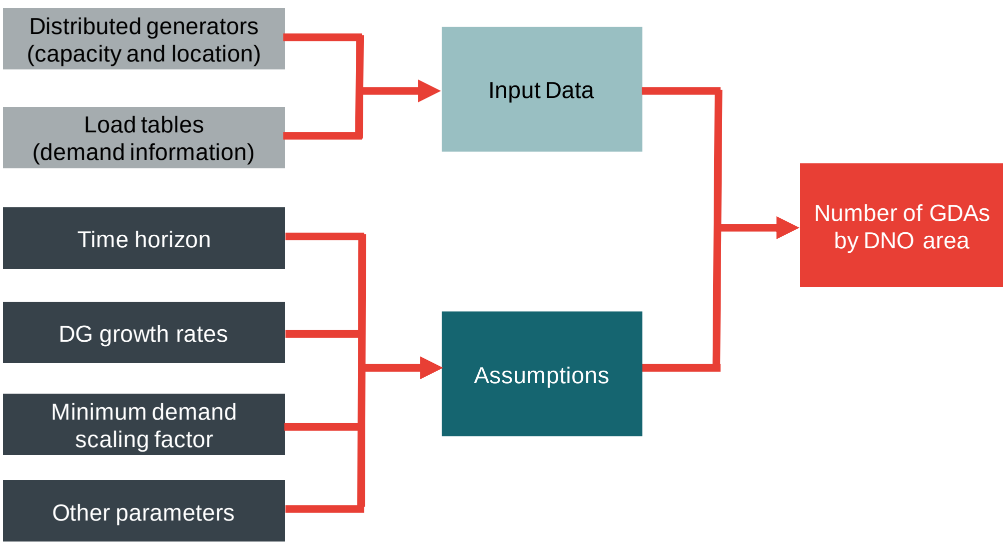
15 This estimate is based on our understanding that UKPN has approximately 121,000 substations and transformers, and that that these account for approximately 25% of the total on the GB distribution network.

the firm capacity). However, it is possible that surplus demand in the maximum demand scenario (i.e., winter) could still exceed surplus generation in the maximum generation, minimum demand scenario (i.e., summer). Moreover, if this winter surplus grows rapidly to the point where it exceeds the level of firm capacity, then a substation will require *demand-led* thermal reinforcement. For this reason, there is a possibility that our method of identification overestimates the true number of primary substations requiring thermal reinforcement as a result of distributed generation. In this respect, therefore, the approach that we have adopted is a conservative one.

3.2 Identification of generation-dominated areas

For each primary substation on the DNO area network, we perform the test outlined in Section 3.1.3 above to identify whether that substation is generation-dominated. As Figure 5 below sets out, in order to perform this test for each primary substation, data is required on the existing demand and generation capacity at the relevant substation. In addition to this, we also need to form a view about a number of parameter assumptions.

Figure 5. Identification process



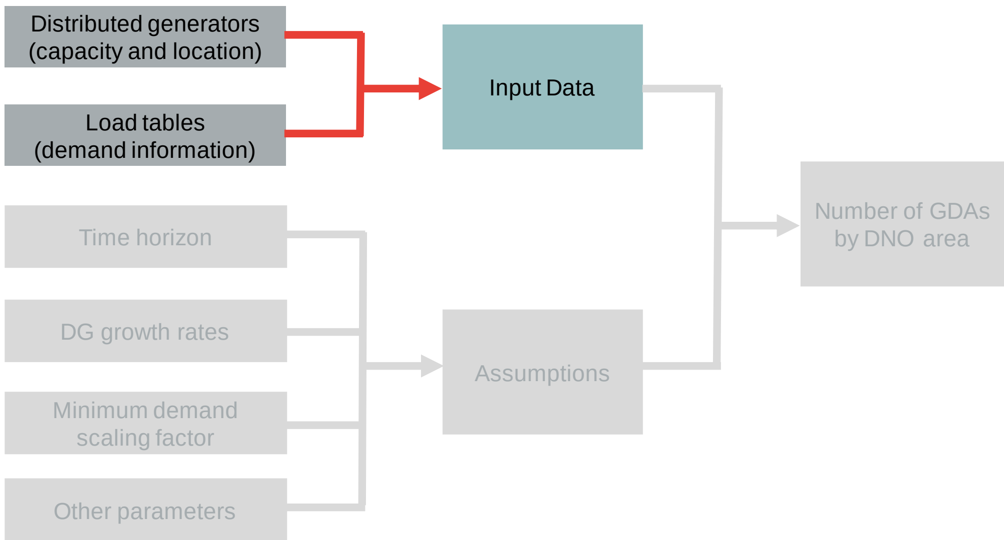
Frontier Economics

The following two sections summarise what input data we have used and explain the parameter assumptions we have made.

3.2.1 Input Data

As shown in Figure 6 below, the method of identification proposed earlier requires a large amount of input data on both existing demand and distributed generation capacity at each primary substation.

Figure 6. Input data for identification



Source: Frontier Economics

We have used primary substation specific data from the Long Term Development Statements (LTDS) for each DNO. This has allowed us to compile demand data (maximum demand and firm capacity) for 4,616 primary substations across 14 DNO areas, and determine the existing level of distributed generation connected to each of these primary substations. Table 2 below summarises the number of primary substations in each DNO area, and the total capacity of existing distributed generation connected in aggregate to these substations as of 2009/10.

Table 2. Summary of number of primary substations and existing distributed generation capacity in each DNO area

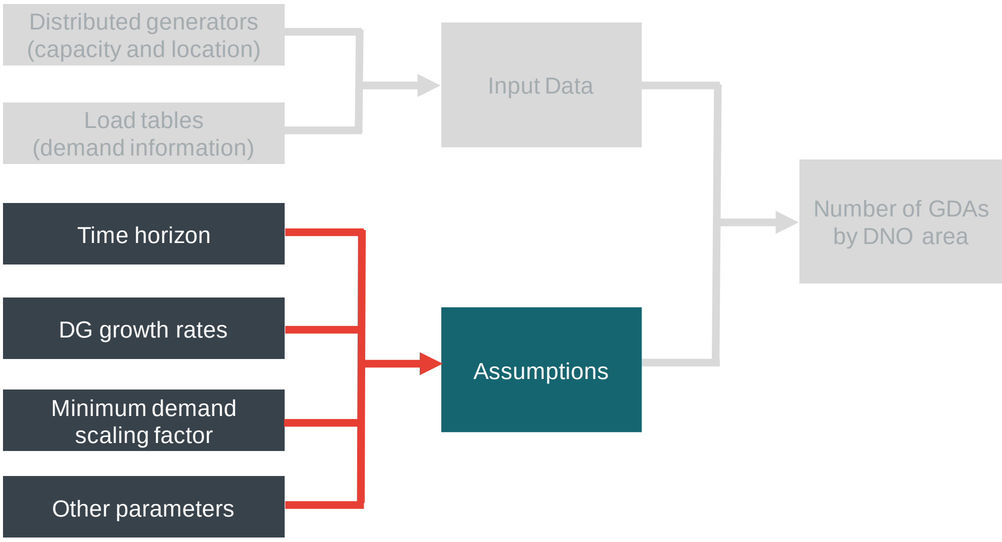
DNO Area	No. of primary substations	Total existing distributed generation (MW)
CE NEDL	196	258.7
CE YEDL	372	495.8
CN EAST	438	269.4
CN WEST	254	461.0
UKPN EPN	456	302.4
UKPN LPN	107	141.9
UKPN SPN	232	344.3
ENW	364	298.6
SPEN SPD	435	101.1
SPEN SPM	340	167.8
SSE SEPD	485	239.0
SSE SHEPD	427	117.9
WPD WALES	188	157.1
WPD WEST	322	116.3
Total	4,616	3,471.3

Source: Frontier Economics

3.2.2 Parameter Assumptions

As Figure 7 below illustrates, we also need to make informed assumptions about four sets of parameters, which we describe in turn and then summarise.

Figure 7. Assumptions for identification



Source: Frontier Economics

Time horizon

Because this is a dynamic test that considers the growth of generation and demand over time, the cut off time period could potentially have an impact on the number of GDAs identified. For our base case, we use a time period of ten years, which is consistent with the time horizon used in other DUoS charging methodologies (e.g., the EDCM 'FCP' methodology). We examine the sensitivity of our results to increasing the time horizon later in this chapter.

Distributed generation growth rates

We have calculated DNO-specific growth rates in distributed generation based on the Forecast Business Plan Questionnaires (FBPQs) from DPCR05.[16] As part of DPCR05, DNOs were asked to predict the total amount of distributed generation expected to connect to each licence area between 2010/11 and 2014/15, by voltage tier (LV, HV, EHV and 132kV). As our analysis focuses on primary substations, we consider the forecast growth in generation on the LV and HV voltage tiers.

In order to analyse both the "hotspot" and the "even growth" scenarios discussed above, we have calculated both a percentage and absolute growth rate implied by the FBPQs for each of the DNO areas. Thus, for each DNO area

16 http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Pages/DPCR5.aspx

there are two growth rates reported, although both imply the same total amount of generation capacity connecting to the network as a whole.

Calculating annual distributed generation growth rates

$$g_{DG\%} = \sqrt[5]{\frac{(DG + ForecastDG)}{DG}} - 1$$

$$g_{DGAbs} = \frac{ForecastDG}{N} \times \frac{1}{5}$$

Where

$g_{DG\%}$ is the annual *percentage* growth rate in distributed generation ("Hot spot" scenario).

g_{DGAbs} is the annual *absolute* growth in distributed generation, measured in MW per primary substation ("Even growth" scenario).

DG is the total existing distributed generation capacity on the DNO area network, measured in MW (as reported in Table 2).

$ForecastDG$ is the total distributed generation forecast to join the DNO network in the next five years according to the FBPQs, at the LV and HV voltage tiers, measured in MW.

N is the number of primary substations on the relevant DNO area.

5 reflects that the FBPQ forecasts are made over a five year period.

The DG growth rates for each DNO area based on the relevant FBPQ forecasts, under the percentage and linear growth scenarios that we use in our analysis, are displayed in Table 3 below.

Table 3. Annual DG growth rates by DNO area (based on FBPQ forecasts)

DNO Area	$g_{DG\%}$	g_{DGAbs} (MW p/substation)	Implied new generation p/yr (MW)
CE NEDL	10.4%	0.168	32.93
CE YEDL	10.1%	0.164	61.01
CN EAST	26.5%	0.275	120.45
CN WEST	15.4%	0.378	96.01
UKPN EPN	14.7%	0.131	59.74
UKPN LPN	10.7%	0.176	18.83
UKPN SPN	7.6%	0.131	30.39
ENW	12.9%	0.136	49.50
SPEN SPD	23.1%	0.085	36.98
SPEN SPM	6.4%	0.036	12.24
SSE SEPD	4.3%	0.023	11.16
SSE SHEPD	16.3%	0.062	26.47
WPD WALES	6.1%	0.058	10.90
WPD WEST	6.2%	0.025	8.05

Source: Frontier Economics

The growth rates above imply a total of 2.9GW of distributed generation connecting to the HV/LV tiers by 2015, as per the FBPQ forecasts.

In order to examine how sensitive our results are to variations in the growth rates of DG, we consider three different *rates* of growth:

- **Low** - 50% of the FBPQ growth rates – implies an additional 2.9 GW of DG connecting to the network by 2021;
- **Medium** – actual FBPQ growth rates – implies an additional 5.8 GW of DG connecting to the network by 2021; and
- **High** – 150% of the FBPQ growth rates – implies an additional 11.6 GW of DG connecting to the network by 2021.

Analysis of Generation-dominated areas

We are therefore able to present the total number of identified generation-dominated areas under three different DG growth rates and two different DG growth patterns ("hotspot" and "even growth"). This implies a total of six different scenarios, which we present in our results section.

Minimum demand scaling factor

The minimum demand scaling factor is used to calculate the level of minimum demand at a substation, utilising the observed maximum demand.

For four of the DNO areas we use primary substation specific data containing minimum demand scaling factors, as provided in the LTDS load tables. For the remaining DNO areas, where substation specific data was not readily available, we have calculated a DNO area wide minimum demand scaling factor making use of the winter peak/summer minimum demand tables at GSP level for 2009/10[17]. These implied minimum demand scaling factors are summarised in Table 4 below:

[17] http://www.nationalgrid.com/uk/sys_09/default.asp?Node=SYS&action=mnchX_1.htm&sNode=15&Exp=Y

Table 4. Minimum demand scaling factors

DNO Area	Min Demand Scaling Factor
CE NEDL	29.3%
CE YEDL	39.0%
CN EAST	31.7%
CN WEST	39.0%
UKPN EPN	Substation specific
UKPN LPN	Substation specific
UKPN SPN	Substation specific
ENW	33.0%
SPEN SPD	36.0%
SPEN SPM	36.0%
SSE SEPD	Substation specific
SSE SHEPD	39.7%
WPD WALES	40.5%
WPD WEST	40.5%

Source: Frontier Economics/NG

Minimum demand growth rate

We apply a minimum demand growth rate of 1%. This is consistent with the growth in demand forecasted between 2010/11 and 2014/15 in the LTDS load data tables. This growth rate is also consistent with assumptions used elsewhere, for example in the EDCM "*Long Run Incremental Cost*" (LRIC) methodology.

Summer: winter ratio

To reflect that the level of firm capacity is lower in summer than winter, we have been advised by the DNOs to multiply firm capacity by a factor of 0.8.

Summary of assumptions

Table 5 below summarises the above assumptions.

Analysis of Generation-dominated areas

Table 5. Summary of parameter assumptions

Parameter	Assumption
Summer/winter ratio	0.8
Time horizon	10 years
Growth in minimum demand	1% p/year for all DNO areas
Growth in distributed generation	50%, 100% and 150% of the rates implied by the FBPQ forecasts from DPCR05
Minimum demand scaling factor	DNO area specific for 4 networks, and DNO area wide for the other DNOs

Source: Frontier Economics

3.3 Results of Generation-dominated areas analysis

In what follows, we present the results of our GDA analysis, both in aggregate across the whole GB distribution network and broken down by DNO area. As discussed above, we consider three different growth rate scenarios and two alternative growth "pattern" scenarios ("hotspot" and "even growth").

3.3.1 Base case results

Table 6 below sets out the total number of generation-dominated areas identified under the proposed test (using the assumptions summarised in Table 5 above).

Table 6. Total number of identified GDAs

		Rate of growth in DG		
		Low (50% of FBPQ)	**Medium (FBPQ)**	**High (150% of FBPQ)**
Pattern of growth in DG	**Hot spot (%)**	79	157	286
	Even (Absolute)	107	146	185

Source: Frontier Economics

The total number of primary substations in our sample is 4,616 meaning that even in the most conservative growth rate/pattern scenario, generation-dominated areas would account for only approximately 6% of all primary substations in 2021. Table 7 below shows the results from Table 6 above expressed as a percentage of the total number of primary substations used in the analysis.

Table 7. Proportion of GDAs as a percentage of total primary substations

		Rate of growth in DG		
		Low (50% of FBPQ)	**Medium (FBPQ)**	**High (150% of FBPQ)**
Pattern of growth in DG	**Hot spot (%)**	1.7%	3.4%	6.2%
	Even (Absolute)	2.3%	3.2%	4.0%

Source: Frontier Economics

In their September 2010 Analysis,[18] the ENA identified 28 (or approximately 0.6% of their total sample) potentially generation dominated primary substations across all DNO areas, by 2020. There are two main reasons the results in Table **6** above exceed those presented by the ENA in September 2010:

- first, our analysis applies significantly higher predicted growth rates in distributed generation than the ENA September 2010 analysis; and
- secondly, our analysis focuses on Summer conditions only, whilst the ENA applied an additional test which sought to first identify "generation heavy areas" where surplus generation exceeds surplus demand (in this sense, our analysis is more conservative than the analysis undertaken in September 2010).

With the exception of the low growth rate scenario, the number of GDAs when the "Hot spot" growth pattern is applied exceeds the number under the "Even" growth pattern. Given that the "Hot spot" growth pattern focuses DG growth on existing DG enabled substations (through the use of a percentage growth rate) and therefore is more concentrated, this result is to be expected. The "Even" growth pattern spreads the same amount of DG growth but over the entire network, and is therefore far less concentrated.

As explained earlier, our identification method makes use of *summer* firm capacity and *minimum* demand. The result of this is that it is possible that the results displayed in Table 6 above overstate the true number of generation-dominated areas.

18 *"CDCM charging condition report to Ofgem – Generation charging in generation dominated areas"*, Energy Networks Association, 1st September 2010

3.3.2 Number of GDAs by DNO area

Table 8 below displays the number of identified GDAs under the "Medium" growth rate scenario by DNO area (results by DNO area under alternative growth rates in generation are provided in Annexe 8.1).

Table 8. Number of GDAs by DNO area (at Medium FBPQ growth rates)

DNO Area	No.of primary substations	*Pattern* of growth in DG	
		Hot spot (%)	Even (Absolute)
CE NEDL	196	6	10
CE YEDL	372	10	8
CN EAST	438	37	2
CN WEST	254	7	5
UKPN EPN	456	19	5
UKPN LPN	107	3	1
UKPN SPN	232	5	1
ENW	364	16	4
SPEN SPD	435	12	3
SPEN SPM	340	7	2
SSE SEPD	485	1	1
SSE SHEPD	427	30	103
WPD WALES	188	3	1
WPD WEST	322	1	0
Total	4,616	157	146

Source: Frontier Economics

Under this growth rate, SHEPD has a large number of generation-dominated areas, most notably when the "Even" generation growth scenario is applied. The SHEPD sample contains 427 primary substations, implying almost 25% of these will be generation dominated by 2021. The primary cause of this result is that there are a number of primary substations in SHEPD with very little firm capacity and low minimum demand, such that a very small addition of generation will trigger reinforcement.

3.3.3 Robustness and sensitivity analysis

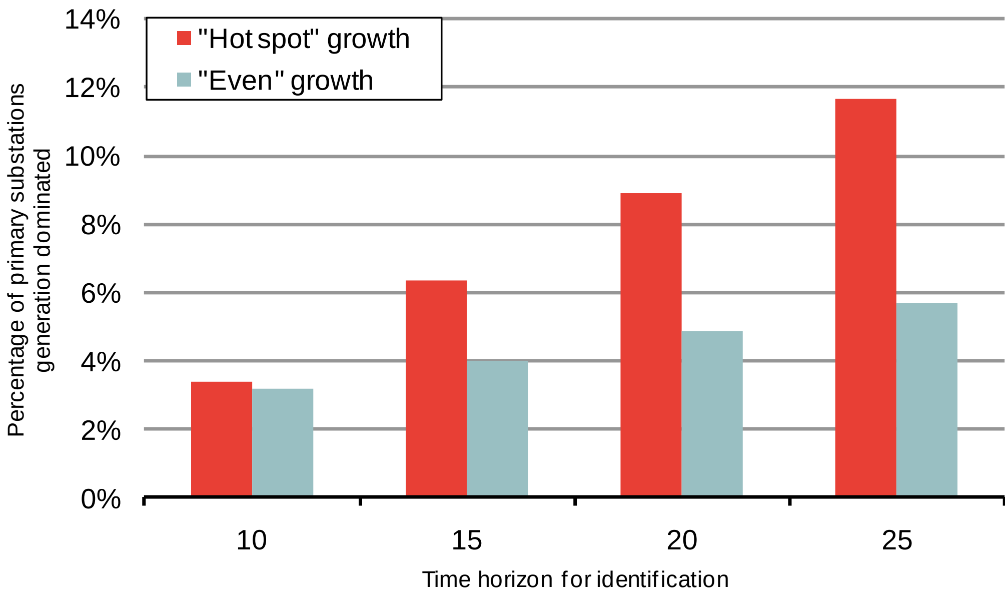
As noted above, one advantage of our identification method is that the parameters used in the analysis outlined above can all be altered, thereby allowing us to test the robustness of these results to different assumptions. In this section, we investigate the effect of modifying:

- the time horizon; and
- the assumed DG growth rate.

Effect of modifying the time horizon

Figure 8 below shows how the percentage of generation dominated primary substations in the sample (inclusive of SHEPD) changes as the time horizon is increased from 10 to 25 years. For each of the different time periods, the FBPQ growth rates from Table 3 are applied annually for the specific time period.

Figure 8. Percentage of primary substations generation dominated as time horizon increases – at medium FBPQ growth rates



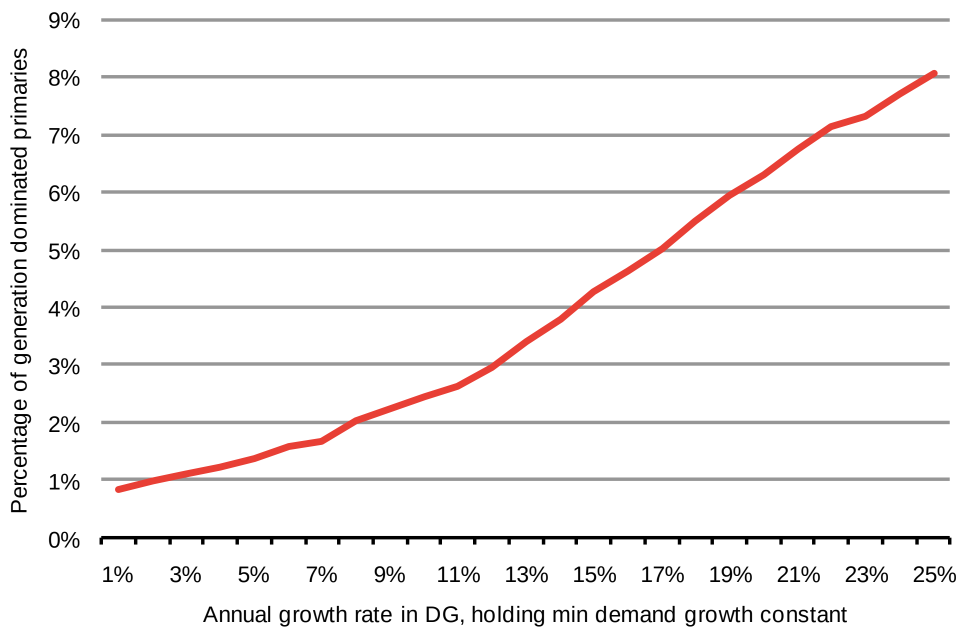
Source: Frontier Economics

The diagram above implies that even if generation grows at the predicted rate for the next twenty five years, only a small proportion of primary substations will become generation dominated by 2035. If medium FBPQ growth rates were sustained until 2035, this would imply a total of 20GW of distributed generation connecting the network.

Effect of varying distributed generation growth rates

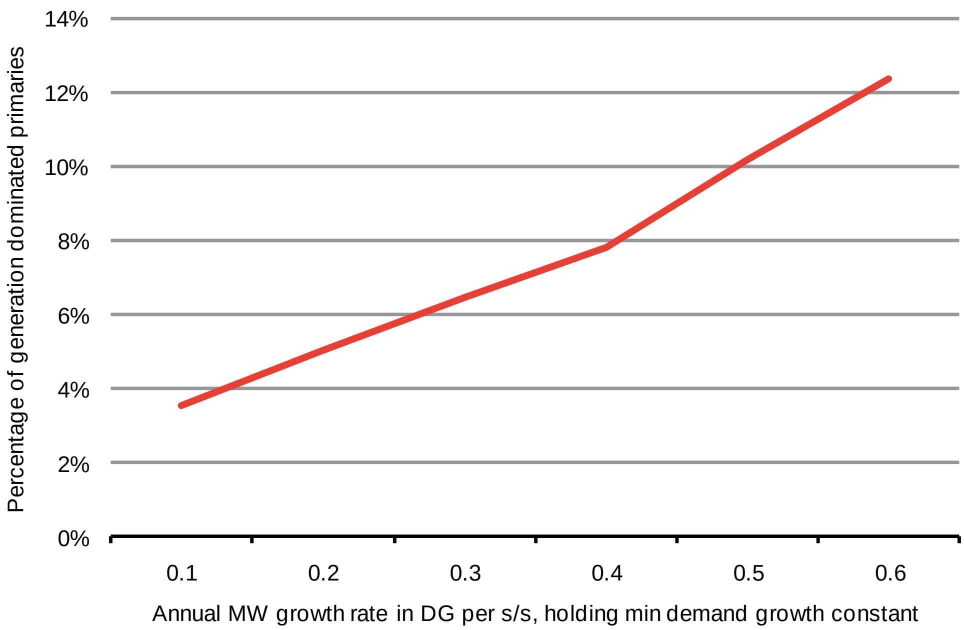
In Figure 9 and Figure 10 below, we display how the percentage of generation dominated primary substations changes as the growth rate of distributed generation increases, over the next ten years (i.e., $t = 10$). In both figures, the same growth rate on the horizontal axis is applied to each DNO area. The vertical axis then displays the total number of identified generation dominated primary substations across all 14 DNO areas, divided by the total number of substations in the sample (4,616). For illustrative purposes, we display only the total across all DNO areas, but more detailed breakdowns by DNO area are shown in Annexe 8.1. For ease of comparison, both graphs imply a maximum of approximately 30 GW joining the total network between 2011 and 2021.

Figure 9. Percentage of Generation Dominated Substations as DG growth rate increases - "Hotspot" scenario



Source: Frontier Economics

Figure 10. Percentage of Generation Dominated substations as DG growth rate increases - **"**Even growth" scenario



Source: Frontier Economics

4 Assessment of the quantifiable costs of introducing locational charges for CDCM generators

In this chapter, we consider the quantifiable costs that would be involved in introducing locational charges for CDCM generators. First, we provide an overview of three high-level options for introducing locational charges. Then, for each of these options, we seek to quantify the costs that DNOs and suppliers would incur if the DNOs were to introduce and maintain such a charging methodology. Since there are a range of potential options for introducing locational charges and uncertainty about the associated costs, we identify a range of potential costs.

4.1 Overview of the different options for introducing locational charges

To evaluate the costs (and the benefits in Chapter 5) to DNOs and suppliers of introducing locational generation charges, we first need to approximate what such a charging methodology might look like. There are a wide range of options for introducing locational generation charges with there being no clear precedent from EDCM (where there are two alternative methodologies for calculating locational generation charges) or read-across from CDCM demand.

There are at least four different dimensions to consider when deciding what a locational charging methodology might look like.

1. **Granularity.** Tariffs could be applied using different levels of granularity. At one extreme, each individual generator could face a different tariff reflecting its unique circumstances. At the other extreme, all generators within a large region could be placed on the same tariff. Tests of whether an area is generation dominated would need to be carried out at the same level of granularity as the locational tariffs are applied. By definition, appropriate data would be required to perform these tests. Cost reflectivity may improve with high granularity, but it would also require more data. High granularity could also result in less transparency and predictability.
2. **Multi-rate.** Tariffs could vary according to the time of the day. At present, some generation tariffs are already multi-rate. Under multi-rate tariffs, credits could be lower (or charges higher) during those times of the day when the network in question is generation-dominated.
3. **Upstream interaction.** In some instances, DG growth might trigger reinforcement on a higher network level. This could lead to several

definitions of generation-dominated areas, which could be reflected in the tariffs. For example, in some areas DG growth at one network level might trigger reinforcement on both the immediate network and also network levels further upstream. In other areas, DG might only trigger reinforcement on either the immediate network level or a network level further upstream. Given the number of network levels, this could result in a large number of potential tariffs.

4. **Voltage level.** Locational charges could be applied to both HV and LV generators. Alternatively, they could apply to only HV generators or, conceivably at least, only LV generators.

These four dimensions alone would lead to tens or even hundreds of possible permutations for introducing locational charging options. However, it would be impossible to consider the cost and benefits of all permutations. Instead, we focus on three high-level options that range from simple to complex. None of the options require credits to be solely positive. They could also be negative implying that, at certain locations, DG could be charged for using the network.

Our three high-level locational charging options are defined as follows.

- **Complex option.**
  - Tariffs would vary on a very granular basis, for example postcode-level[19].
  - The tariffs would apply to both HV and LV generators.
  - Multi-rate tariffs would be used in all cases where the required metering was in place.
  - The tariffs would take account of the impact of DG on both the assets immediately surrounding the point at which that DG connects to the network and the assets at network levels further upstream. For example, DG that triggered reinforcement of assets at both its immediate network level and further upstream would receive lower credits (or higher charges) than DG that solely triggered reinforcement at its immediate network level (other things being equal).
- **Intermediate option.**
  - Tariffs would vary on a moderate level of granularity, for example primary substation level[20].

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19 Although one DNO informed us that even using a postcode level of granularity would not be fully cost reflective since addresses within a given postcode can be connected to different substations.

20 This would be roughly equivalent to town-level granularity.

    - They would apply to both HV and LV customers.
    - Multi-rate credits (or charges) would be used for all non-intermittent tariffs.
    - The tariffs would not reflect the impact of DG on assets further upstream

- **Simple option.**
    - The simple option would be similar to the intermediate option except it would only apply to HV generators. We decided to have an option exclusively for HV generators, because we thought that the costs involved with locational charges may be significantly reduced without sacrificing too high a proportion of the benefits.
    - Only a limited number of new tariffs would be introduced, such that the DNOs would not require new Line Loss Factors (LLFs). A defining feature of the simple option is therefore that the DNOs would be able to implement it by modifying their current tariff and billing systems, rather than having to set up new systems.

Table 9 below provides a summary of our three high-level locational charging options.

Table 9. Summary of our three options

	Complex	Intermediate	Simple
Voltage level	HV and LV	HV and LV	LV
Granularity of tariffs	High e.g. postcode level	Medium e.g. primary substation level	Medium e.g. primary substation level
Multi-rate	Yes for generators where there is adequate metering	Yes for non-intermittent generators	Yes for non-intermittent generators
Consider impact on assets further upstream	Yes	No	No

Source: Frontier analysis

These three options are not intended to be detailed charging methodologies. Rather, we are trying to ascertain whether the benefits associated with locational charging could justify the costs of introducing and maintaining such a regime, and, if so, what such a locational charging regime may look like in high-level terms. We have specified a broad range of options, so that there is an upper and lower bound of both the costs and the benefits. The results of the study can then be used to inform the development of future charging proposals that build on our high-level finding and focus in on the optimal locational charging methodology.

4.2 Evaluation of the quantifiable costs potentially associated with each charging option

In the following sections, we first set out how we estimated the costs that DNOs would be likely to incur as a result of introducing locational charges. We then present the DNOs' estimated costs as well as potential supplier costs.

4.2.1 Process used to estimate the costs to DNOs

Based on workshops with the DNOs, we developed a survey to evaluate the costs that DNOs would be likely to incur if they introduced one of our three high-level locational charging options. This survey focussed on the following types of costs (the specific survey questions are reprinted in Annexe 8.2).

- **Methodology.** The DNOs would need to spend time on developing an appropriate methodology for introducing locational charges. This would need to "bolt-on" to the current CDCM methodology. Experience from the EDCM suggests that such tasks can potentially be time-consuming particularly when there are a high number of affected parties.
- **Collect and updating data.** Some of our options may require the DNOs to collect new data. This is especially true of our complex option where DNOs would need to test whether very small areas, for example postcodes, are generation dominated. This would require DNOs to have data on firm capacity, minimum demand and installed generation at a very geographically granular level. Such data would also need to be updated on a relatively frequent basis so that locational charges remain cost reflective over time. Collecting data may require additional metering equipment to be installed as well as man hours. The intermediate and simple options may not require much new data to be collected initially, but there are still likely be costs involved with keeping this data up-to-date.
- **Derive tariffs.** The data would need to be input into a system or spreadsheet that then calculates the tariffs for different types of generators. At present, the CDCM tariffs are calculated using a spreadsheet model. A complex option for locational charges might require a more advanced system to be developed to be able to handle

the volume and complexity of the data and calculations required. By definition, it should be possible to implement the simple option using the current system for deriving tariffs.

- **Generate invoices.** The DNOs would need to send invoices to suppliers that showed each individual generator's tariff, generation data and associated credits/charges. The invoices would need to specify different charges for each generator, which could result in hundreds or even thousands of line items for each invoice to suppliers.
- **Send invoices to suppliers.** The generated invoices would need to be sent to suppliers either electronically or using a paper-based system. If the invoices are sent electronically then it may form part of the same system that generates the tariffs and invoices.
- **Resolve disputes with suppliers.** Suppliers may have queries about the generation data or the tariff that generators have been placed on. There may be more disputes under a more complex option relative to the intermediate and simple options since it may be more difficult to determine which tariff a particular generator should be placed on.

For many of the survey questions, we asked about the number of FTE days that would be required as we considered that the DNOs would be more familiar with thinking in such terms. We then assumed that an FTE day costs £500 per day.

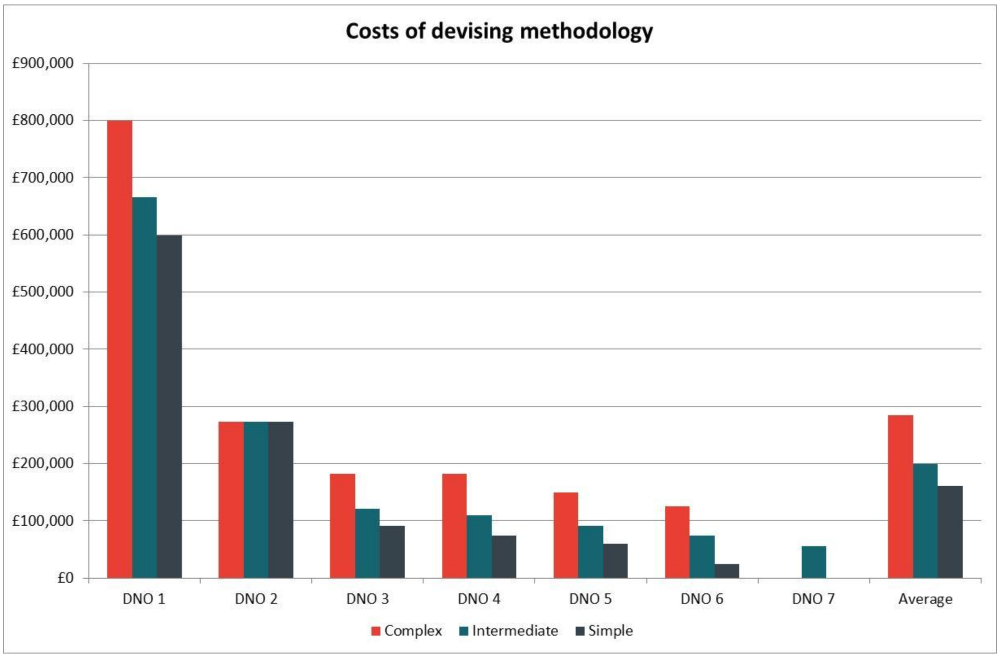
The DNOs suggested that they would probably jointly develop the methodology and the system to derive tariffs. Therefore, for these two types of costs we asked about the joint costs to DNOs whereas for the other types of costs we asked about the DNO specific costs. We also asked the DNOs about what the costs would be under a 'no change option'. We did this so that we could identify the incremental (additional) costs associated with introducing locational charges.

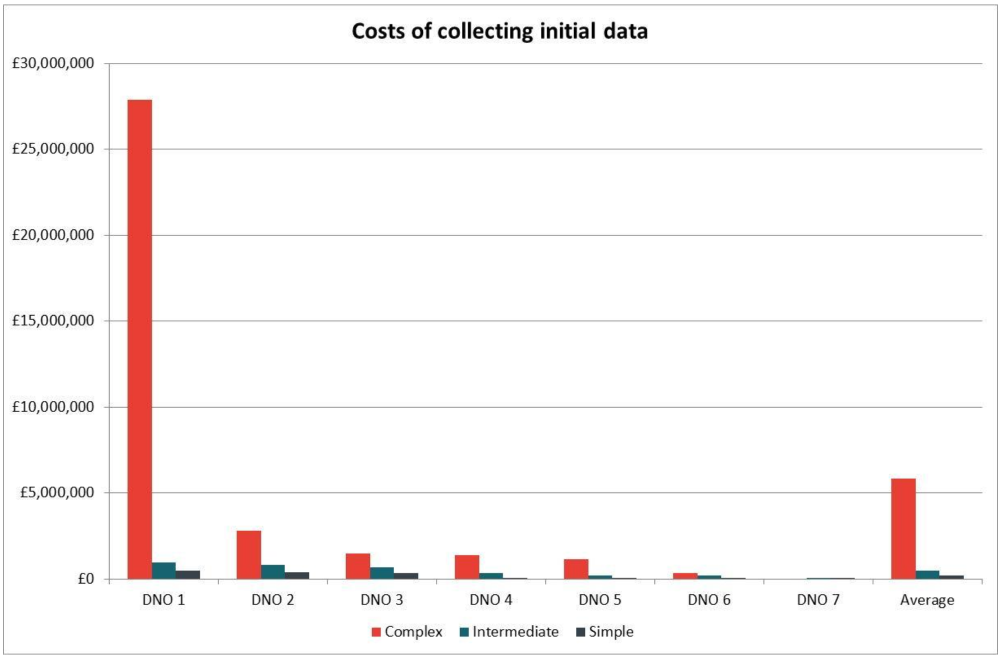
One DNO considered that the complex option would be practically impossible until smart metering is implemented. We have therefore excluded this DNOs' cost estimates from our analysis.

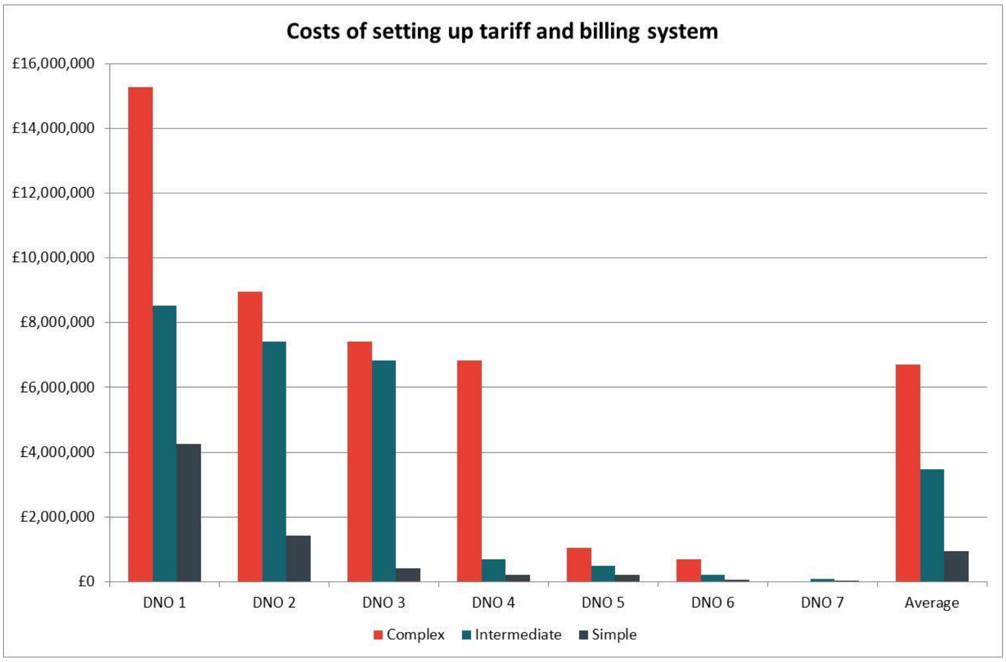
4.2.2 Costs to DNOs

In this section, we present the DNOs' estimated costs. We have anonymised the DNOs costs and ranked them in order. Figure 11 shows the DNOs' various set-up costs.

Figure 11. DNOs' estimated set-up costs (ranked in order)



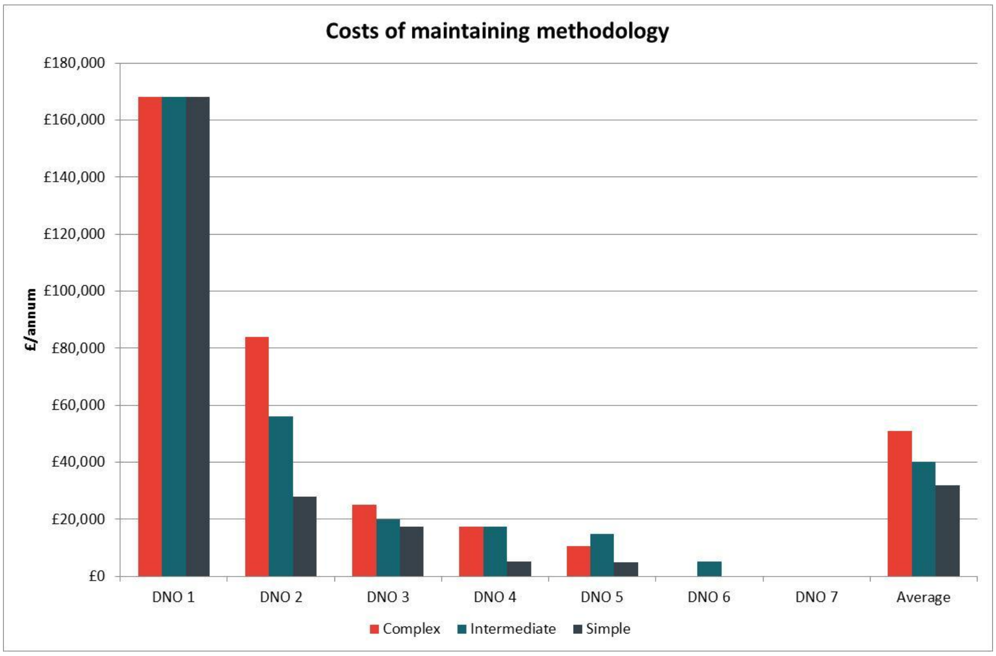


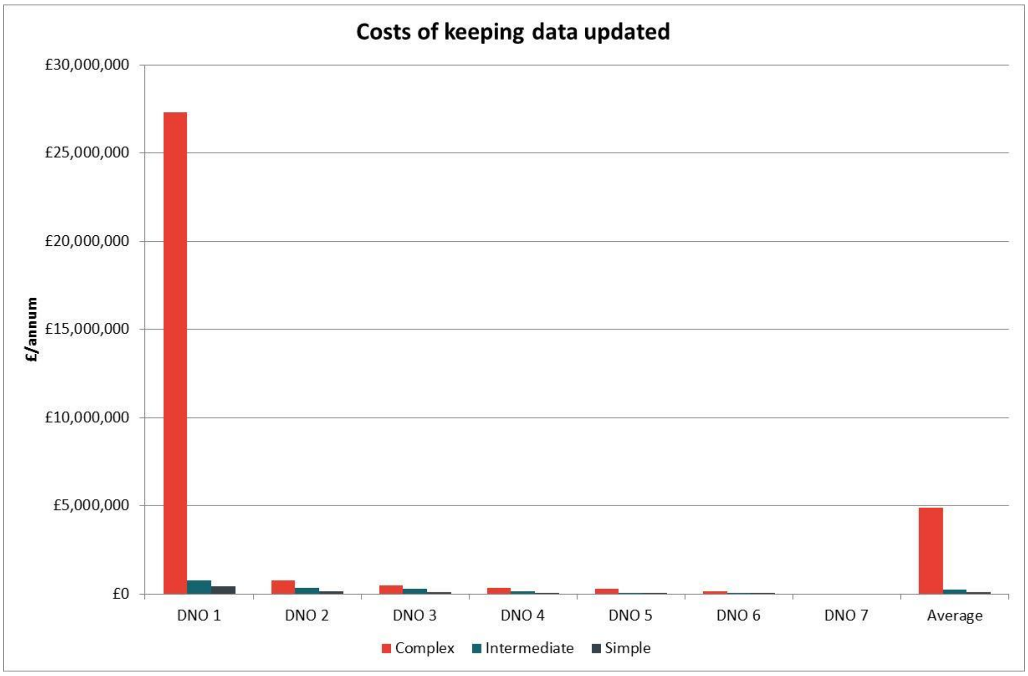


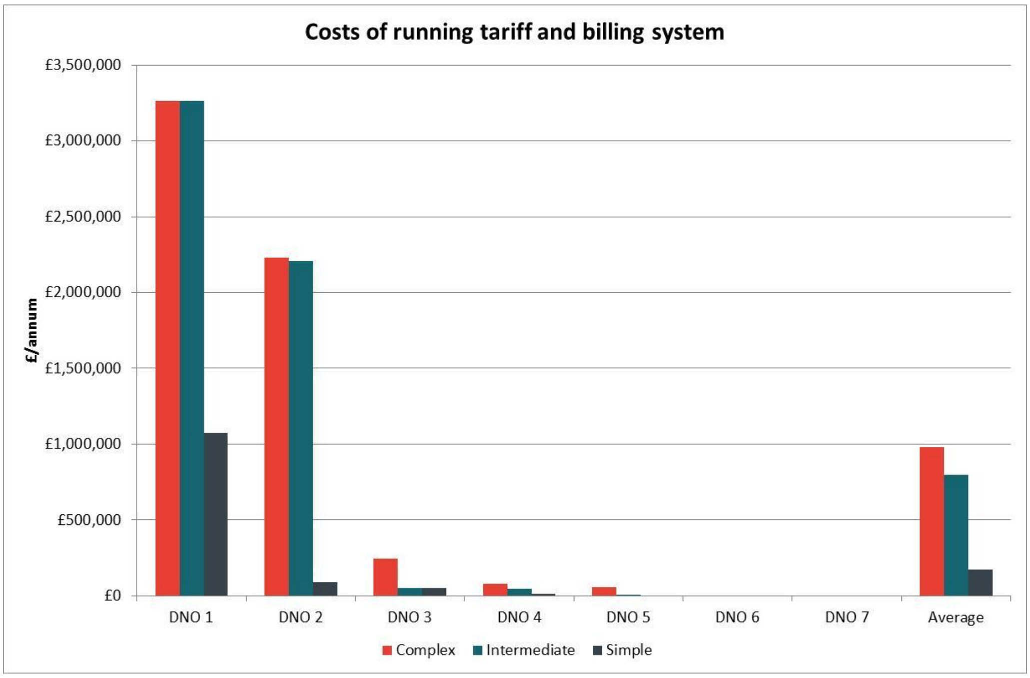
Source: Survey completed by DNOs

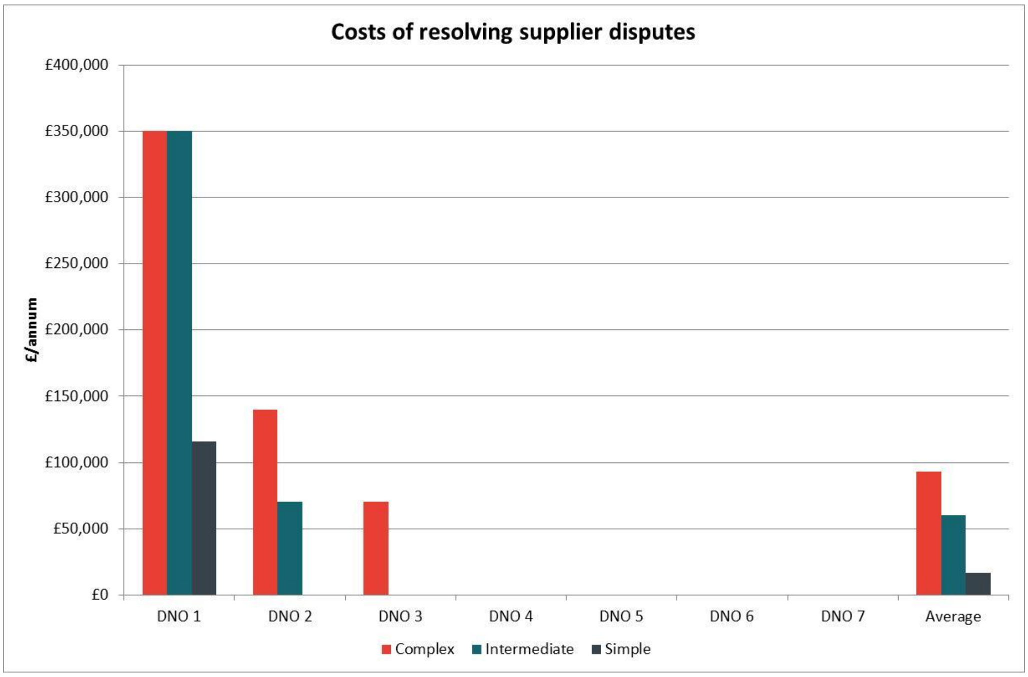
Figure 12 shows the DNOs' estimated ongoing costs for each of the three options.

Figure 12. DNOs' estimated ongoing costs (ranked in order)









Source: Based on survey completed by the DNOs

Figure 11 and Figure 12 show that there was significant variation across the DNOs' cost estimates for some categories. We consider this to be reasonable for the DNOs' tariff and billing systems since they will currently have different capabilities. For example, those DNOs that have recently installed new billing systems might reasonably be expected to incur less cost. The variation in the cost estimates also highlight that there is significant uncertainty about the likely costs of introducing a locational charging methodology.

Based on the survey responses, it became clear that the DNOs had made different assumptions about the quantity of data that would need to be collected under the complex option. The DNO with the very high cost estimate for data collection had assumed that data would need to be collected at every single distribution substation, whereas other DNOs had assumed that only a sampling approach would be taken. We have therefore decided to present two cost estimates for the complex option throughout the rest of this chapter. One considers the costs of collecting data at every single distribution substation. The other considers the costs of using a sampling approach to data collection. Collecting and updating data at every single substation was considered very costly, so there is a large divergence in the two cost estimates for the complex option.

Figure 13 summarises the DNOs' predicted set-up costs associated with introducing the complex (full data and sampling approach), intermediate and simple options[21]. The DNOs estimated that the set-up costs would be around £35.1m for the complex option if data at all distribution substations were collected. This results in the cost of the complex option with full data being significantly higher than the costs of the complex option with sampling. The set-up costs of the intermediate and simple options were even lower still, although still significant. There are also considerable costs associated with the system(s) that would be used to derive the tariffs, generate the invoices and send the invoices to suppliers.

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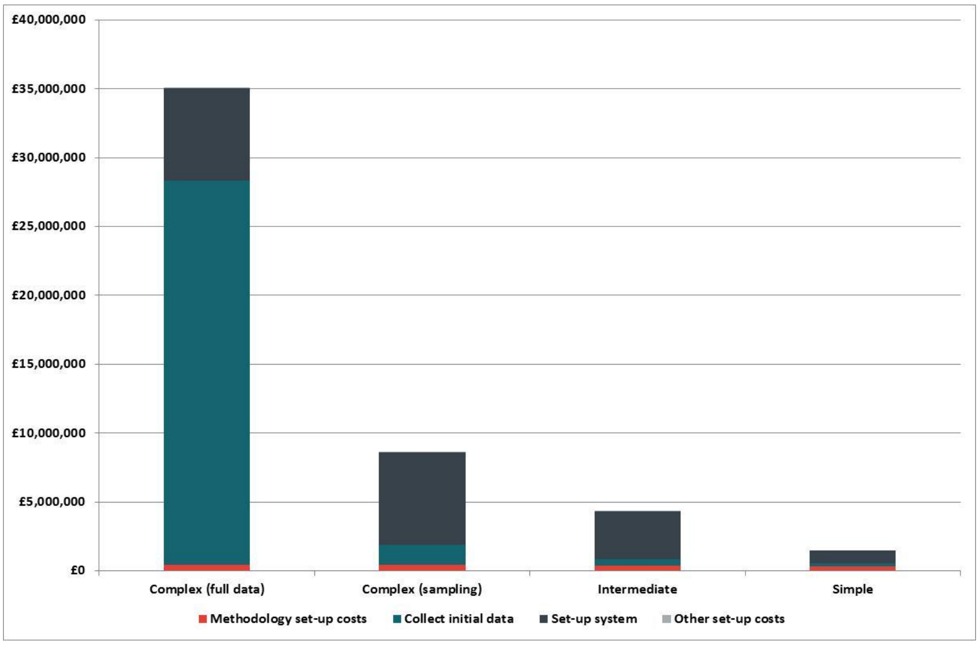
21 We have taken an average of the DNOs' estimates. For those questions that asked about DNO-specific costs, we upscaled the estimates to cover all DNOs before taking an average. For example, we multiplied UKPN's cost estimates by 14/3 for the DNO-specific costs. Based on discussions with the DNOs, we have also added £150k of consultancy costs to setting up the methodology under all the options.

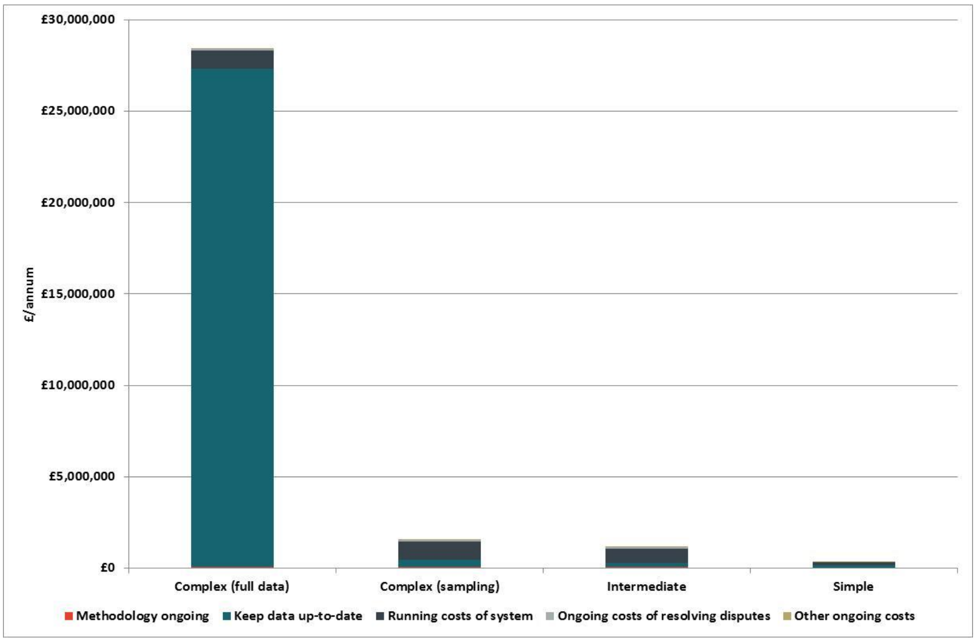
Figure 13. DNO set-up costs (total for all DNOs)



Source: Survey completed by the DNOs

The ongoing costs of the complex option hinge on whether all data on distribution substations is collected or whether the DNOs just take a sample. If the DNOs collect all data, then the estimate of ongoing costs is £28.4m per year across all DNOs. Under a sampling approach the ongoing costs of the complex option would fall to £1.5m. Although using a sample would reduce the costs, it would also reduce the potential benefits as tariffs would be less cost reflective. The intermediate option has moderate ongoing costs of £1.1m per year across all DNOs. The simple option has low ongoing costs of £336.4k per year across all DNOs.

Figure 14. DNO ongoing costs (total for all DNOs)



Source: Survey completed by the DNOs

Given that the costs involve a mixture of set-up costs and ongoing costs, we calculated the total discounted costs for each of the options over a ten year period[22]. The complex option with full data collection has discounted costs of £254.6m, which is significantly higher than the cost of the complex option with sampling (£20.6m). The intermediate option has more moderate costs of £13.1m and the simple option has relatively low costs of £4.1m.

Table 10. DNOs' total set-up and ongoing costs discounted over a ten year period

	Complex (full data)	Complex (sampling)	Intermediate	Simple
DNO costs (NPV)	£254.6m	£20.6m	£13.1m	£4.1m

Source: Based on survey completed by the DNOs

22 Using a discount rate of 5 per cent.

4.2.3 Costs to suppliers

For locational charges to carry any benefits, suppliers must pass on the DNOs' charges to generators. Suppliers are likely to incur a range of costs in passing on these locational charges. We have identified the following potential cost categories.

- **Verify that invoices are correct.** The suppliers would need to ensure that the invoices that they receive from the DNOs are correct. This may involve both checking that the generation data is correct and verifying that generators have been placed on the correct tariff.
- **Add credits/charges to other charges to generate bills.** Generation use of system credits (or charges) will only form one component of the credits (charges) that generators receive (pay). For example, generators also receive Feed-In-Tariffs (FITs) for the electricity they generate. All of these credits (or charges) will need to be aggregated to calculate an overall credit (or charge) for the generator.
- **Send bills to customers.** Suppliers will need to send bills to generators either electronically or using a paper-based system. The associated costs may not necessarily be higher with locational charges unless the bills become more detailed.
- **Deal with queries and complaints from generators.** Generators may query the generation data or may question the tariff they have been placed on.

Given the narrow time frame for our project, we have not conducted a detailed survey of suppliers' potential costs. However, we have been in contact with a major supplier to discuss the potential costs that suppliers would incur if locational charges were introduced. We have assumed that suppliers would incur the same level of costs as DNOs, excluding the costs of devising and maintaining the methodology, and collecting the data. The methodology and data costs are not really relevant to suppliers. This means that we have assumed that suppliers will incur the same costs regardless of whether the DNOs collect data on all, or only a sample of, distribution substations under the complex option. The following table shows the suppliers discounted costs over a ten year period.

Table 11. Suppliers' total set-up and ongoing costs discounted over a ten year period.

	Complex (full data)	Complex (sampling)	Intermediate	Simple
Supplier costs (NPV)	£15.1m	£15.1m	£10.2m	£2.5m

Source: Frontier assumptions

4.2.4 Total DNO and supplier costs

In this section, we bring together the DNOs' costs with the suppliers' costs. In the next chapter, we then compare these aggregated costs with the potential benefits from introducing locational charges. From Table 12 it is evident that large benefits would be required to justify the costs of the complex option with full data collection. Even the costs of the simple and intermediate options are sufficiently large to justify careful consideration before introducing locational charges.

Table 12. Total set-up and ongoing costs across DNOs and suppliers discounted over a ten year period.

	Complex (full data)	Complex (sampling)	Intermediate	Simple
DNO costs (NPV)	£254.6m	£20.6m	£13.1m	£4.1m
Supplier costs (NPV)	£15.1m	£15.1m	£10.2m	£2.5m
Total DNO and supplier costs (NPV)	**£269.7m**	**£35.7m**	**£23.3m**	**£6.6m**

Source: Frontier assumptions.

5 Evaluation of the potential benefits of introducing locational charges

In Chapter 4, we sought to quantify the costs of setting up and maintaining locational charges for HV and LV generators. We now consider the potential benefits of introducing such a charging regime.

As discussed in Chapter 2, cost-reflective locational generation charges could, in principle at least, incentivise more efficient siting decisions, which would manifest themselves in reduced network reinforcement costs. They could do this in two ways:

- first, locational charges could incentivise some generators to locate in demand-dominated areas rather than generation-dominated areas, provided that technological and planning constraints allow them to do so; and
- secondly, locational charges could simply deter some generation capacity from connecting to the network at all.

Both of these effects could reduce the rate of generation capacity growth in generation-dominated areas, thereby preventing – or at least deferring – the need for network reinforcement.

In order to quantify these potential benefits associated with locational generation charges, we first of all need to identify the 'typical' cost that would be avoided if locational charges were to prevent the need for further network reinforcement in a generation-dominated area. This chapter sets out how we have identified this 'typical' reinforcement cost.

The remainder of this chapter is split into three sections:

- first, we provide an overview of a survey that we submitted to the DNOs to help identify these typical reinforcement costs;
- secondly, we provide an overview of the responses that the DNOs provided to this survey; and
- thirdly, we explain and discuss how we used these responses to calculate the typical reinforcement costs that would be incurred if generation capacity steadily grew to the extent that, at times, the reverse flows exceeded the rating of a primary substation.

In what follows, we discuss each of these sections in turn.

5.1 Overview of survey submitted to the DNOs

This section sets out how we estimated the reinforcement costs that could be averted if new generation were to locate in demand-dominated areas rather than generation-dominated areas. We asked the DNOs to estimate the typical asset requirements and the associated costs that they incur with generation-led reinforcement. We asked them to focus on a scenario in which generation capacity steadily grew to the extent that, at times, the reverse flows exceed the rating of a primary substation. We were interested in the reinforcement requirements of assets both immediately upstream and downstream of the primary substation, as well as those of the substation itself. Table 13 sets out a summary of the survey that we asked the DNOs to complete.

Table 13. DNO survey on generation-led reinforcement costs

	Transformers	Switch gear	Circuits (km)	Circuit terminations	Other
Typical reinforcement needs (# units)					
Typical asset reinforcement costs (£/unit)					

Source: Frontier Economics

To ensure that our estimates were robust, we asked the DNOs whether the reinforcement costs varied systematically depending on the type of substation, for example 33kV/11kV compared to 33kV/6.6kV. We also asked about the typical capacity that would be added as a result of the reinforcement to check whether the DNOs' estimates were comparable.

5.2 Overview of DNO responses to this survey

As set out above, the survey asked the DNOs to provide information about:

- what assets would typically need to be reinforced if generation capacity steadily grew to the extent that, at times, the reverse flows exceeded the rating of a primary substation; and
- the typical unit reinforcement costs for each of these asset groups.

In what follows, we provide an overview of the responses that the DNOs provided to each of these two sets of questions.

5.2.1 Typical asset reinforcement requirements

The DNOs all considered that two additional transformers would be required. There was less consensus, however, on the amount of switchgear and length of circuit that would typically be needed. For example, one DNO thought that no switchgear would be required whereas another considered that 15 units would be needed. From subsequent discussions with the DNOs, we understand that this level variation in the 'typical' asset reinforcement requirements is unsurprising, given the different characteristics of the networks that the DNOs operate.

Table 14. Typical asset reinforcement requirements[23]

	Transformers[24]	Switchgear	Circuits (km)	Circuit terminations
Highest DNO estimate	2	15	20	2
Lowest DNO estimate	2	0	0	0
Median	2	4	6	0
Mean	2	6	7	1

Source: Survey completed by DNOs

We have decided to use the mean of the reinforcement requirements to calculate the typical reinforcement costs. The typical reinforcement cost would have been lower if we had used the median. Our approach is therefore conservative, as it will lead to a higher estimate of the potential benefits than using the median would have.

The DNOs generally considered that between 5MVA and 20MVA of capacity would be added as a result of a typical reinforcement. We consider this to be a

23 One DNO estimated the asset requirements assuming that the reverse flow would not exceed the sustained rating of the transformer. This meant that this DNO's estimates of the reinforcement requirements were much lower than the other DNOs' estimates. We have therefore excluded this DNO's estimates from Table 14 and our cost estimates in the following sections.

24 One DNO suggested that reinforcement often simply involves increasing the size of existing transformers rather than purchasing additional transformers. Our approach may, therefore, be conservative in that it overestimates the typical reinforcement cost in some cases.

sufficiently narrow range for us to treat the DNOs' asset requirements as comparable.

A few DNOs mentioned that there might be other assets that would require reinforcement. For example, one DNO considered that Watts and Vars transducers would be required to monitor the direction of the power flow. We have decided not to include any other assets since most DNOs did not view them as being of significant cost. Therefore, their exclusion will not have a material impact on our estimate of the typical reinforcement cost.

5.2.2 Typical unit reinforcement costs for these assets

There was considerable variation in the estimated unit costs, especially for switchgear. We have taken the mean of the unit cost estimates. The mean unit costs are higher than the unit costs that Ofgem used in the DPCR5, which are more in line with our median estimates. Our approach is therefore conservative, as we may be overstating the potential benefits from introducing locational charges.

Table 15. Asset unit costs

	Transformers	Switchgear	Circuits (km)	Circuit terminations
Highest DNO estimate (£)	1,000,000	725,000	600,000	10,000
Lowest DNO estimate (£)	310,000	28,500	250,000	5,000
Median (£)	389,750	50,000	275,000	7,500
Mean (£)	523,250	210,520	339,280	7,500

Source: Survey completed by DNOs

Several of the DNOs did not think that the reinforcement costs would vary depending on the type of primary substation. Those DNOs who did think that the costs would vary did not consider that the costs would vary drastically. We are therefore confident that our unit costs serve as a good approximation for the reinforcement costs of a typical primary substation.

5.3 What these responses imply about the 'typical' reinforcement cost

Table 16 below shows how we have used these DNO survey responses to estimate the typical reinforcement costs that would be incurred if generation capacity steadily grew to the extent that, at times, the reverse flows exceeded the rating of a primary substation. Specifically, we have multiplied the mean asset requirements (as set out in Section 5.2.1) by the mean unit costs for these assets (from Section 5.2.2) to calculate the implied total reinforcement cost for each asset group, as shown in the bottom row of Table 16. Adding together these total asset costs implies a total 'typical' reinforcement cost of about £4.7m.[25] The DNOs have confirmed that this is an appropriate estimate to use as an average across the DNOs.

Table 16. Implied typical reinforcement cost

	Transformers	Switchgear	Circuits (km)	Circuit term-inations	TOTAL
Asset requirement (mean) (# units)	2	6	7	1	-
Unit cost (mean) (£)	523,250	210,520	339,280	7,500	-
Implied reinforcement cost (£)	1,046,500	1,263,120	2,374,960	7,500	**4,692,080**

Source: Survey completed by DNOs

Our approach focuses on the typical reinforcement cost of a primary substation and the assets immediately surrounding it. In theory, it is possible that distributed generation growth could also trigger the reinforcement of assets further downstream. However:

- the DNOs explained to us that the majority of reinforcement costs would be incurred on the primary substation;
- LTDS forecasts show that the DNOs expect the majority of DG to connect to the HV rather than LV network over the next five years; and
- the DNOs also thought that it would be rare for generation to exceed demand at the LV level. For example, domestic CHP will tend to be used when the house is occupied and therefore demand is high. In

25 The DNO whose cost estimates we excluded did state that a typical reinforcement would cost at least £5m if the reverse power flow exceeded the sustained rating of the transformers. This estimate is in the same ballpark as our £4.7m estimate.

addition, the expansion of demand-side management (following the rollout of smart meters, for example, or with the increasing use of electric vehicles) could help to increase local electricity demand on the LV network during times of high generation.

For these reasons, we consider our cost estimate to be a good approximation of the reinforcement cost that would be averted if locational generation charges were to deter further generation growth in a generation-dominated area.

In some cases, locational signals could encourage generation to move from a generation-dominated area to a demand-dominated area. In such instances, reinforcement costs would not only be avoided in the generation-dominated area, but could also potentially be avoided in the demand-dominated area. This would lead to a further benefit of locational charges, a so called 'double dividend'.

In practice, however, we view such a scenario as unlikely. We have decided not to reflect the possibility of a 'double dividend' in our assessment of the potential benefits for two reasons.

- **Intermittent generation.** A significant proportion of distributed generation that is currently forecast to connect to the LV and HV levels is intermittent generation. For reinforcement to be avoided in demand-dominated areas, DNOs would need to be confident that generation would offset peak demand. With intermittent generation, there is no guarantee that electricity will be generated during peak hours, as is reflected by low F-factors. This is especially true of solar energy, which will mainly produce electricity during the day in the summer months when demand is low.

- **Lack of responsiveness of CHP to locational charges.** CHP is the main type of non-intermittent generation that is forecast to connect to the LV and HV networks. However, the decision of where to locate small-scale CHP is likely to be driven by many factors other than just locational charges. This would make small scale CHP unresponsive to locational charges. In particular, households with domestic CHP generators would be unlikely to move house just because of locational charges; rather, at most, such generators would simply stop generating altogether in response to a particularly high local DUoS charge. Clearly, such generation will do nothing to obviate demand-led reinforcement if it simply stops generating rather than relocating to a demand-dominated part of the network.

6 Comparison of the costs and benefits of introducing locational generation charges

Introducing locational generation charges would only be justified if the potential benefits of doing so – as estimated in Chapter 5 – were to outweigh the costs of setting up and maintaining such a charging regime, as identified in Chapter 4. In what follows, therefore, we examine whether the potential benefits of introducing such a charging regime could plausibly be large enough to justify the costs. We do this in two stages:

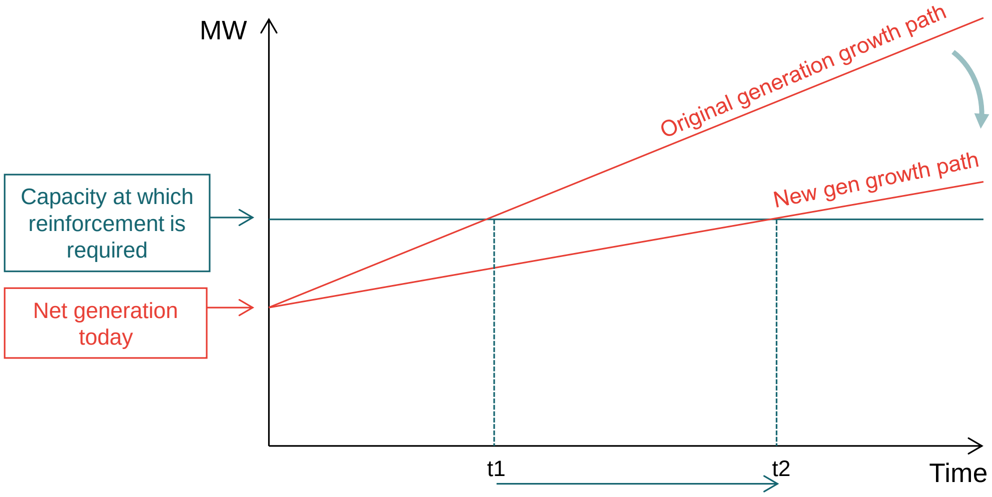
- first, in Section 6.1, we draw together the quantitative analysis presented in Chapters 3 to 5 to calculate the **minimum reduction in generation growth rates** required in each generation-dominated area to justify the costs of introducing and maintaining the locational charging regime estimated in Chapter 4; and
- secondly, in Section 6.2, we form a view about whether it is **plausible to assume that locational charges could have such an effect** on generation growth in these generation-dominated areas.

We discuss each of these stages in turn.

6.1 Identifying the minimum reduction required in generation growth rates

As discussed in Chapter 2, cost-reflective locational generation charges could, in principle at least, incentivise more efficient siting decisions. As Figure 15 illustrates, this could reduce the cost of reinforcement in these generation-dominated areas in net present value (NPV) terms.

Figure 15. Overview of how locational charges could reduce network reinforcement expenditure by slowing down generation growth in generation-dominated areas



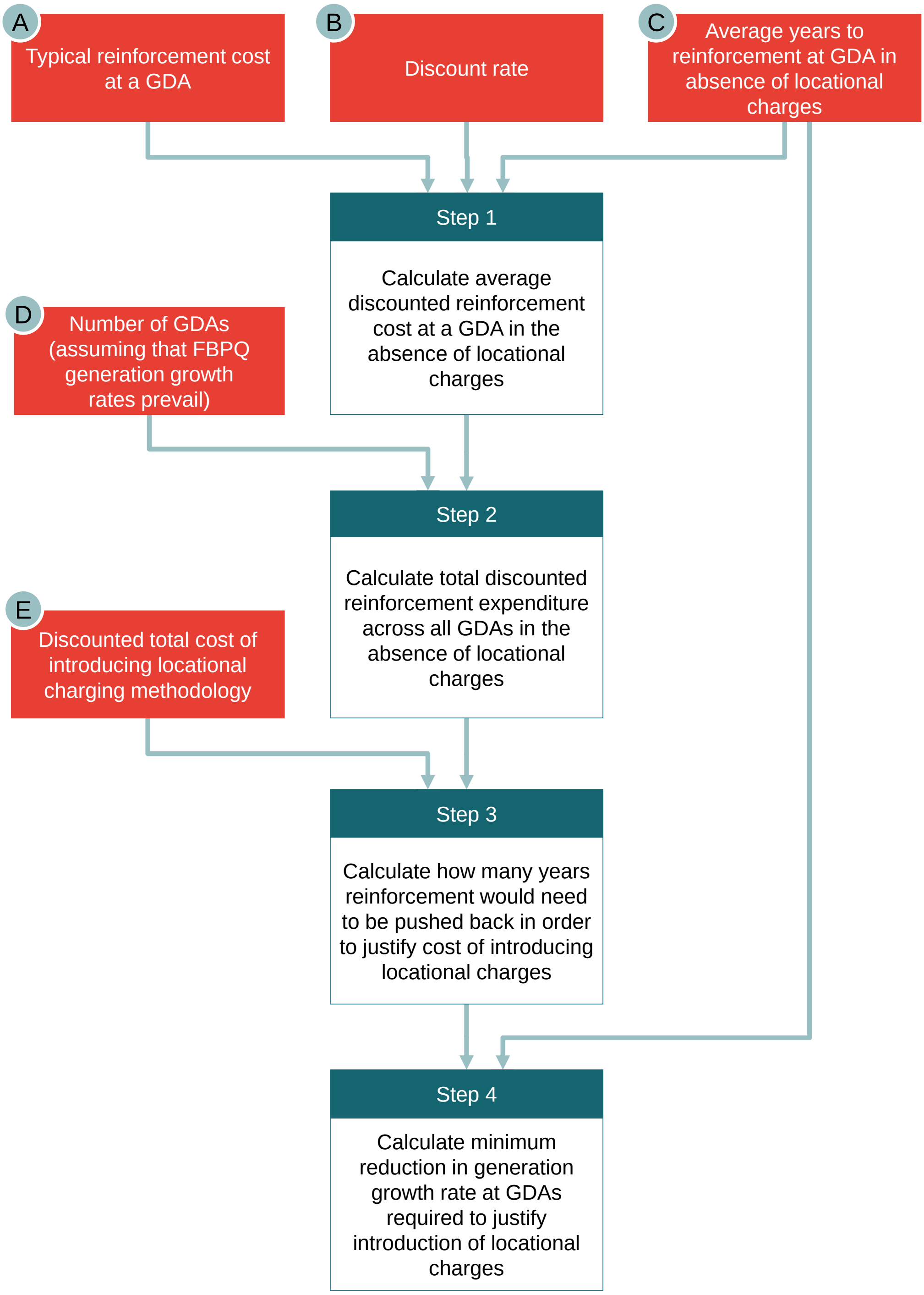
Source: Frontier Economics

As Figure 15 illustrates, locational generation charges could, in principle, reduce the rate of growth in net generation at a generation-dominated primary substation, thereby pushing back the date at which reinforcement is required from *t1* to *t2*. This scenario would be consistent with locational generation charges deterring some – but not all – new distributed generation capacity from siting at that location on the network. Because this reinforcement is deferred to *t2*, the net present value of this reinforcement cost will fall. This potential reduction in the reinforcement cost, we understand, is widely held to constitute the key theoretical benefit of introducing locational generation charges.

We now use the 'typical' reinforcement cost estimate identified in Chapter 5 to calculate the ***minimum reduction in generation growth rates in GDAs*** that locational charges would need to bring about in order to justify the total cost of introducing and maintaining each locational charging regime. In other words, we estimate how many years network reinforcement would need to be pushed back in GDAs in order to justify the cost of introducing such a charging regime.

Figure 16 below provides a schematic overview of the methodology that we have used to calculate this required reduction in annual generation growth rates.

Figure 16. Overview steps to used calculate the minimum required reduction in annual generation growth rates at each generation-dominated primary substation



Source: Frontier Economics

As Figure 16 illustrates, this methodology requires the following five sets of inputs.

A. **The typical primary reinforcement cost** – £4.7m, as identified in Chapter 5.

B. **The relevant discount rate.** We have assumed a discount rate of 5%[26], in line with the discount rate that we understand is typically used for DNOs and other regulated companies.

C. **The number of years before reinforcement would be required at each generation-dominated primary substation in the absence of locational charges**. This can be calculated by expanding on the analysis of generation-dominated areas presented in Chapter 3. We have calculated this to be 7.2 years on average.

D. **The number of generation-dominated primary substations.** In Chapter 3, we estimated that generation growth could trigger reinforcement at 157 primary substations within the next 10 years, should FBPQ growth forecasts prove accurate. We therefore assume here that there are 157 GDAs.

E. **The total discounted 10-year cost of introducing and maintaining each possible locational charging regime** – Our analysis in Chapter 4 yielded the following NPV cost estimates for each of the charging options:

Table 17. DNOs' and suppliers' discounted costs over a 10-year period

	Complex option (full data collection)	Complex option (sampling)	Intermediate option	Simple option
Total DNO and supplier costs (NPV)	£269.7m	£35.7m	£23.3m	£6.6m

Source: Based on survey completed by the DNOs – see Chapter 4

Using these data inputs and parameter assumptions, we can calculate the minimum reduction in generation growth rates in GDAs that locational charges would need to bring about in order to justify the costs identified in Chapter 4. As Figure 16 above illustrates, this calculation involves the following four steps.

26 We carried out sensitivity analysis and found that small changes in the discount rate did not have a material impact on our results.

Step 1 – calculate average discounted reinforcement cost at a GDA in the absence of locational charges

As we identified in Chapter 5, the 'typical' reinforcement cost that DNOs would incur if generation growth were allowed to continue unchecked in a generation-dominated area amounts to £4.7m. However, these costs would not be incurred immediately in the absence of locational generation charges; rather, as noted above, on average continued generation growth would only trigger thermal reinforcement in a typical GDA after 7.2 years. Therefore, the average typical reinforcement cost in NPV terms is actually just £3.3m (i.e., a typical cost of £4.7m that is on average incurred 7.2 years into the future, assuming a 5% discount rate).

Step 2 – calculate total discounted reinforcement expenditure across all GDAs in the absence of locational charges

By multiplying the average discounted GDA reinforcement cost estimate (i.e., £3.3m) from Step 1 by the number of GDAs (i.e., 157), we can calculate total discounted reinforcement expenditure across all GDAs. This comes to approximately £519m.[27] This can be interpreted as the maximum possible benefit that introducing locational charges could deliver – in other words, if introducing locational charges succeeded in preventing any future reinforcement at all 157 generation-dominated areas, this would reduce total network expenditure by £519m in present value terms. In practice, of course, the benefit of introducing locational charges is likely to be considerably less than £519m – not least because it is likely that locational generation charges will simply delay reinforcement, by slowing down the rate of generation growth in GDAs, rather than averting the need for reinforcement in these areas altogether.

Step 3 – calculate how many years reinforcement would need to be pushed back in order to justify cost of introducing locational charges

In Step 2, we estimated that total discounted reinforcement expenditure across all DNOs would sum to £519m in NPV terms in the absence of locational charges. However, we also know from Chapter 4 that it would cost between £6.6m and £269.7m to introduce and maintain locational charges, depending on the

27 An alternative 'bottom up' approach to the one set out here would be to calculate the number of years until reinforcement would be required in the absence of locational generation charges for each of the 157 GDAs separately. One could then calculate separate NPV network reinforcement costs for each of the GDAs and then add these costs together to derive an alternative measure of the total NPV reinforcement cost across all GDAs in the absence of locational generation charges. In practice, however, using this this more convoluted 'bottom up' approach rather than the approach set out in the text above would appear to have little material effect on the results of our analysis.

complexity of the charging regime (see Table 17 above). Based on this, we can calculate how many years reinforcement would need to be pushed back in order to justify the cost of introducing locational charges. This minimum number of years is set out in Table 18 below.

Table 18. Calculating the minimum number of years that reinforcement would need to be pushed back in order to justify the cost of introducing locational charges

	Complex option (full data collection)	Complex option (sampling)	Inter-mediate option	Simple option
Total reinforcement expenditure across all GDAs in absence of locational charges (in NPV terms) – from Step 2	£519.3m	£519.3m	£519.3m	£519.3m
Total cost of introducing and maintaining charging regime (in NPV terms) – from Chapter 4	£269.7m	£35.7m	£23.3m	£6.6m
Difference between these two costs	£249.6m	£483.6m	£496m	£512.7m
Implied number of years reinforcement would need to be pushed back in order to justify the cost of introducing locational charges	**15.0**	**1.5**	**0.9**	**0.3**

Source: Frontier Economics

As Table 18 sets out, the cost of introducing and maintaining a charging regime for the most complex option (for example) sums to £269.7m in NPV terms. This implies that the benefits of introducing the complex charging regime would only outweigh the costs if these complex locational charges reduced the NPV of the network reinforcement cost across generation-dominated areas by *at least* £269.7m – or from £519.3m to £249.6m. Assuming a 5% discount rate, this reduction in the NPV can be shown to be equivalent to pushing back the average number of years to reinforcement at a GDA by *at least* 15 years. By contrast, in order to justify introducing the less complex locational charging options, one would only need to show that these charging regimes would push back reinforcement in generation-dominated areas by between 0.3 and 1.5 years on average.

Comparison of the costs and benefits of introducing locational generation charges

Step 4 – calculate minimum reduction in generation growth rate at GDAs required to justify introduction of locational charges

Finally, we can use the results from Step 3 to calculate the minimum reduction in the annual generation growth rate in generation-dominated areas required to justify the cost of introducing of locational charges. This is a straightforward calculation. For example:

- in Step 3, we calculated that in order to justify the introduction of the most complex option for locational generation charges, those locational signals would need to push back network reinforcement by 15 years on average;
- in other words, generation charges would need to increase the average number of years before reinforcement from 7.2 years to 22.2 years; and
- this can be shown to be equivalent to reducing the annual growth rate in generation capacity in generation-dominated areas by 68%.[28] For example, under the growth rates predicted in the FBPQ forecasts, this would require a reduction in the annual growth rate in distributed generation from approximately 12% to 4%.

Table 19 below sets out the reduction in the generation growth rate required to justify introducing locational charges for both the 'complex' option and the other charging options.

28 Required reduction in growth rate = 1 – (7.2 / 22.2) = 68%

Table 19. Calculation of minimum reduction in generation growth rate required to justify each of the options for introducing locational generation charges[29]

	Complex option (full data collection)	Complex option (sampling)	Inter-mediate option	Simple option
Average number of years to reinforcement in a GDA in absence of locational charges	7.2	7.2	7.2	7.2
Minimum increase in number of years to reinforcement required to justify introducing locational charges	15.0	1.5	0.9	0.3
Implied reduction in generation growth rate in GDAs required to justify introduction of locational charges	**68%**	**17%**	**12%**	**3%**

Source: Frontier Economics

The results set out in Table 19 suggest that:

- in order to justify the cost of introducing the most complex option for locational generation charges, one would need to be confident that such a charging regime could bring about a reduction in the generation growth rate in generation-dominated areas of nearly 70%;
- stripping out the costs of data collection, however, significantly reduces the required benefit associated with the complex option – in this scenario, a reduction of at least 17% in the generation growth rate would suffice;
- in order to justify the cost of introducing the 'intermediate' option for locational generation charges, one would need to be confident that such a charging regime could reduce the annual generation growth rate in generation-dominated areas by at least 12%; and

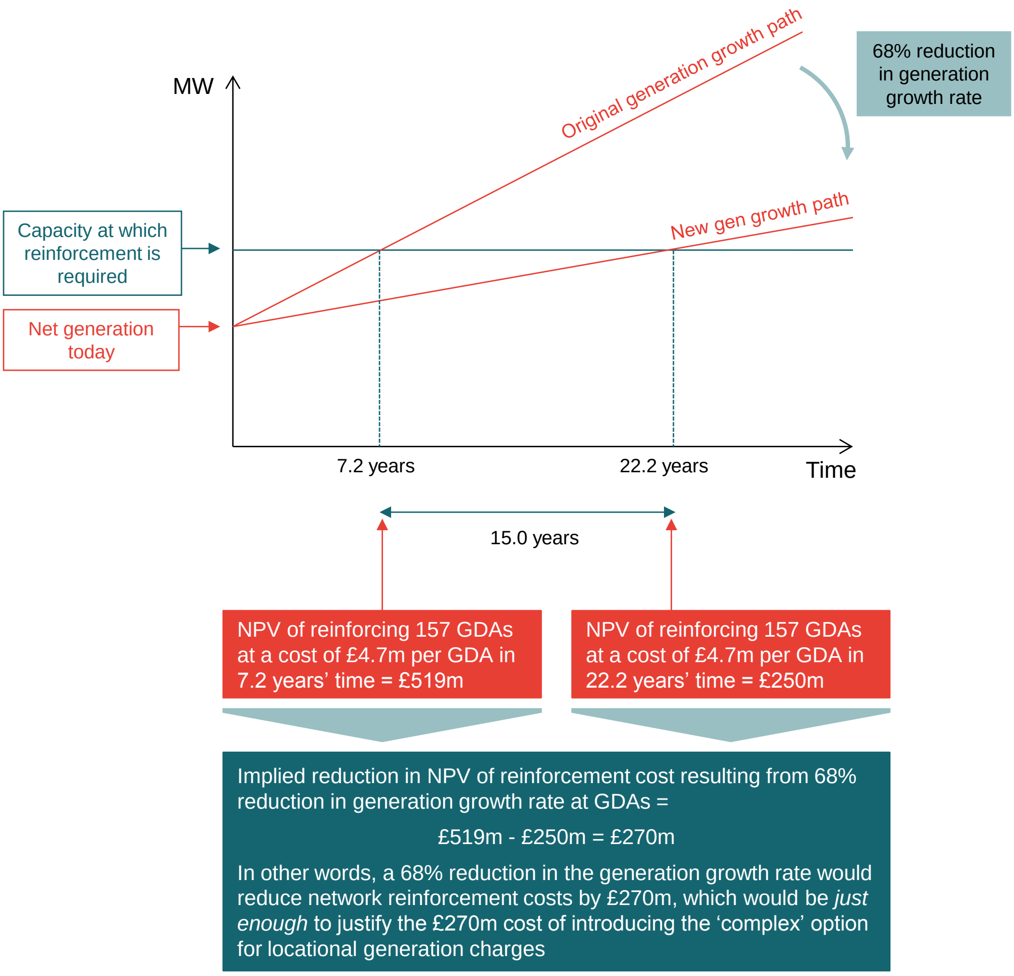
29 It should be noted that the approach we have adopted here is a conservative one, in that we consider the benefits over an infinite time horizon, even though our analysis of the costs was based on a 10-year horizon. For example, as Table 19 sets out, a 68% reduction in the generation growth rate would only justify the £270m cost of introducing the complex option if we consider the total benefits that this could provide be pushing reinforcement back by a full 15 years (from 7.2 years to 22.2 years into the future), rather than focusing exclusively on benefits over the next 10 years.

Comparison of the costs and benefits of introducing locational generation charges

- in order to justify the cost of introducing the 'simple' option for locational generation charges, one would need to be confident that such a charging regime could reduce the annual generation growth rate in generation-dominated areas by at least 3%.

Figure 17 below provides a further illustration of how a 68% reduction in the annual generation growth rate in generation-dominated areas would bring about a network investment cost saving that is just enough to justify the total cost of introducing and maintaining the most complex locational charging option.

Figure 17. Illustration of how a 68% reduction in the generation growth rate would be just enough to justify the cost of introducing the 'complex' locational charging option



Source: Frontier Economics

As Figure 17 above sets out:

- a 68% reduction in the annual generation growth rate across generation-dominated areas would increase the average number of years before reinforcement is required from 7.2 years to 22.2 years;
- this would reduce the NPV of reinforcing the 157 GDAs from £519m to £250m – i.e. an overall reduction of £270m; and
- this reduction in the NPV of the future reinforcement cost would be *just enough* to justify the £270m cost of introducing and maintaining the most complex locational generation charging methodology.

Comparison of the costs and benefits of introducing locational generation charges

6.2 Evaluation of results

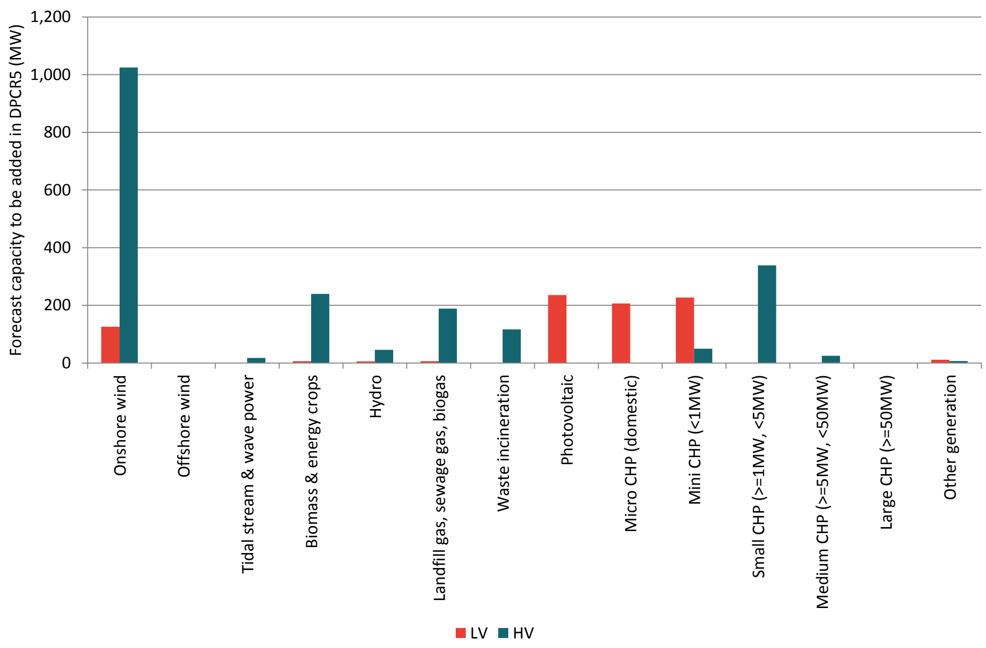
We would argue that the quantitative analysis set out above points to three key conclusions.

Conclusion 1: there would appear to be a strong case for rejecting the data-intensive complex option – at least for the time being

Our quantitative analysis suggests that, in order to justify the cost of introducing the most complex option for locational generation charges, one would need to be confident that such a charging regime could bring about a reduction in the annual generation growth rate across GDAs of at least 68%. However, it strikes us as highly improbable that locational DUoS charges alone could unilaterally bring about such a significant reduction in growth rates in generation-dominated areas for the following reasons.

- **First, in practice, many generators will only have limited choice about where to locate on the network.**
  - As Figure 18 below indicates, wind generation accounts for a significant proportion of the generation capacity that is forecast to connect to the HV and LV networks over the next five years. While wind may be more footloose than some sources of electricity generation (for example hydroelectricity), it nonetheless faces a number of technological and regulatory constraints that limit the number of available sites at which it can profitably connect to the network.
  - Figure 18 also indicates that domestic microgeneration accounts for a comparatively sizeable share the forecast generation growth over the next five years. These domestic customers would only be able to locate elsewhere on the network by moving house – and it would be highly unrealistic to assume that variable generation charges alone could elicit such a response. Instead, the choice facing these customers will not be over *where* to locate on the network, but rather whether to install any microgeneration at all.

Figure 18. Breakdown of generation capacity forecast to be added to the HV and LV networks in DCPR5



Source: DNO Forecast Business Plans for DPCR5

- **Secondly, DUoS charges would be just one component of a suite of charging signals that generators receive.** For demand customers, DUoS charges only currently account for 17% of typical total electricity bill. If locational DUoS charges were to end up being of a similar order of magnitude for generators, it seems improbable that these charges alone could be large enough to reduce generation growth rates in GDAs by as much as 68% on average. Moreover, in addition to this, there are a number of generation-specific financial incentives that could further 'swamp' the DUoS signal – the average annual feed-in tariff (FIT) for a typical domestic solar PV generator in GB, for example, sums to more than ten times the average annual DUoS bill.[30]

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30 Ofgem states that distribution charges make up 17 per cent of a typical electricity bill of £424 (17%*£424=£72).

(http://www.ofgem.gov.uk/Media/FactSheets/Documents1/updatedhouseholdbillsjan11.pdf).

The Energy Saving Trust calculates that a typical solar PV generator (2.2kwp) would earn households £800 per year through FITs.

(http://www.energysavingtrust.org.uk/Generate-your-own-energy/Sell-your-own-energy/Feed-in-Tariff-scheme).

Conclusion 2: there may be some value to waiting until the smart meter roll out gets underway

Although it would be prohibitively expensive for DNOs to introduce the 'complex' charging methodology as things stand today, we also understand from discussions with the DNOs that these costs could fall significantly if smart metering were rolled out across the country.

- As was set out in Section 4.2.1 above, data collection costs alone account for considerably more than half of the total £269.7m cost of introducing and maintaining the complex methodology. Once these data collection costs are stripped out, the cost of the complex option falls to just £35.7m.

- However, we understand that a significant proportion of these data collection costs will end up being incurred anyway if smart metering is rolled out across the country. With smart meters installed across every household and business, the DNOs should have access to all the power flow data they need to calculate cost reflective locational generation charges on a highly granular basis (e.g., postcode level).

This suggests that there may be a stronger case for considering the introduction of the 'complex' locational generation charging methodology following the completion of the planned rollout of smart meters than there is today.

Conclusion 3: for the less complex charging options, the results of the quantitative cost-benefit analysis are less clear-cut

Our analysis points to the following conclusions about the minimum benefits required to justify the costs of introducing the 'intermediate' and 'simple' locational charging regimes:

- On the one hand, the intermediate option would need to bring about a reduction in generation growth of 12% across generation-dominated primary substations. This would suggest that there may be a case for rejecting both the intermediate option and the complex option with sampling *unless* there were clear evidence that a significant minority of generation customers would change their locational behaviour in response to these signals.

- However, based on our quantitative cost-benefit analysis alone, there does *not* appear to be a strong case against the simple option for introducing and maintaining locational generation charges.

Taken together, the above conclusions suggest that, while there is a strong case against introducing a complex locational charging methodology (or, at the very least, not before the smart meter roll out has been completed), there may be a case for introducing a simpler charging regime whereby DNOs send a broad locational charging signal to HV generation customers that makes use of their existing data collection and billing systems capabilities. As was explained in Chapter 4, this simple methodology:

- would send locational charging signals to HV generation customers, but not LV generation customers;
- would send locational charging signals, but on a relatively aggregated basis (for example, charges might only vary across groups of primaries); and
- would not take account of the effect of HV and LV generation growth on network assets upstream of the primary substation.

It should be emphasised, however, that this conclusion is based exclusively on our analysis of those costs and benefits that we have been able to quantify. As was noted in Section 2.3 above, introducing locational generation charge may also create additional risks that cannot easily be quantified. Unfortunately, the fact that these potential costs are difficult to quantify does not necessarily render them insignificant. We therefore turn to these additional 'qualitative' considerations in Chapter 7.

7 Consideration of other qualitative factors

The analysis set out in Chapter 6 focused on the quantifiable costs and benefits that would be associated with introducing locational CDCM charges for HV and LV generators. However, as was noted in Chapter 2, we also need to consider any advantages and disadvantages that are difficult to quantify. In particular, careful consideration should be given to:

- the issue of whether suppliers would pass on locational charging cost signals to end customers;
- the implications of each of the locational charging options for simplicity, transparency and predictability of charges; and
- the interaction of locational charges with other energy policies and objectives.

We consider each of these issues in turn.

7.1 Would suppliers pass on locational charging cost signals?

For locational generation charges to deliver any benefits at all, it is vital that suppliers pass these charging signals directly on to end customers. There would be little point in generating locational charging signals with the intention of influencing network users' siting behaviour if those signals were then blocked before they even reached these users.

In our view, however, it is far from obvious that suppliers would wish to pass on such locational charges, particularly if those charging signals vary on a granular basis (e.g., postcode from postcode) as would be the case under the 'complex' option. In particular, suppliers are likely to be wary of any development that would further complicate the already-complex system of tariffs that they levy on end customers. The suppliers will, no doubt, be mindful of Ofgem's recent warning[31] that customers are "*bamboozled*" by "*tariff complexity [that] has increased from 180 to more than 300 since 2008*" and its resolution to "*sweep away this complexity so suppliers' prices are fully exposed to allow easy price comparisons*". Passing on locational generation charges to end customers, would bring about a further increase in the number of tariffs – such a regime could, potentially, result in many of thousands of tariffs, depending on the granularity of the locational signal. This could leave suppliers vulnerable to the accusation that they are working against Ofgem's push for simpler practices.

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31 See: http://www.ofgem.gov.uk/Media/PressRel/Documents1/RMRFinal%20Final.pdf

For these reasons, it seems likely that suppliers would resist any move that would require them to pass locational charging signals down to end customers, especially those at the LV level. In light of this, careful consideration needs to be given to the issue of how suppliers could be persuaded or required to pass on these signals under the current regime.

7.2 Implications for simplicity, transparency and predictability of charges

In its May 2005 consultation on the longer term framework for the structure of electricity distribution charges,[32] Ofgem outlined a number of other high-level principles for distribution charges to "sit alongside" the principle of cost reflectivity. Three of these further principles were:

- simplicity;
- transparency; and
- predictability.

As we noted in Chapter 2, the principles of predictability and transparency are in many ways as important as that of cost reflectivity in facilitating efficient network use. As Ofgem pointed out in its 2005 consultation paper, this is because "*long term [siting] decisions will be based on expectations of future costs, rather than solely on current charges, so it is important that future charges are predictable, as far as possible, and that reasonable expectations are not overturned without good reason*."

In light of this, any benefits associated with introducing more cost reflective charges must be balanced against the associated drawbacks in the form of increased methodological complexity and reduced transparency and predictability. Indeed, we understand that this need to strike an appropriate balance between cost reflectivity on the one hand and simplicity, predictability and transparency on the other was one of the key justifications for introducing two separate distribution charging methodologies – one for EHV network users (the EDCM) and the other for LV/LV network users (the CDCM).

The decision to introduce the more computationally complex and data intensive EDCM for EHV network users was justified on the basis that large EHV network users (such as power plants and industrials) would be likely to be more responsive to price signals than HV or LV network users (particularly domestic customers). This greater perceived sensitivity to pricing signals meant, again

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32 See Ofgem document "Structure of electricity distribution charges. Consultation on the longer term charging framework". May 2005

http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/10763-13505.pdf correctly in our view, that the EDCM should place more weight than the CDCM on cost reflectivity and less weight on simplicity, predictability and transparency. Any change to the CDCM that significantly shifted the emphasis away from simplicity, predictability and transparency towards cost reflectivity would therefore require careful justification – again, this would be particularly true if this shift occurred at the LV level.

7.3 Interaction with other energy policies and objectives

Careful attention should be paid to the potential interaction of locational CDCM generation charges with other energy policies and objectives to make sure that the introduction of such charges would not have undesirable unintended consequences in these fields. In particular, careful consideration should be given to:

- any effect that the need to pass on locational charges might have on barriers to entry in the electricity supply market; and
- any effect that locational charges could have on the growth of distributed generation capacity and the UK's ability to meet its 2020 renewables targets.

In what follows, we discuss each of these issues in turn.

7.3.1 The 'complex' option as a barrier to entry into the electricity supply market?

One "unintended consequence" might relate to the dynamics of competition between suppliers: as was noted in Chapter 4, a highly granular charging methodology that, for example, required suppliers to bill customers on a postcode basis could require suppliers to invest in expensive new billing systems. Any resulting increase in upfront investment costs could, in principle, constitute a barrier to entry for new suppliers. Any such effect would require careful consideration, not least because DNOs are required to facilitate competition in the supply of electricity.

7.3.2 Could locational charges impede the UK's ability to meet its 2020 renewables target?

Attention should also be paid to any effect that locational generation charges could have on the UK's ability to meet its target to source 30% of its electricity from renewable sources by 2020. As was noted above, introducing locational charges could involve a significant transfer of risk to small generation customers: instead of being guaranteed a fixed credit for use of the network, these customers would have to account for the possibility that charges could vary over time at any given location. For example, a generation customer could connect to part of the network where charges are low (or even negative) only for charges to increase dramatically and unexpectedly as a result of an event that is beyond its control (for instance a large generator connecting to the same part of the network, resulting in a reversal of power flows across the local primary substation).

Nor is this only a theoretical concern. Recent experience with the reform of the EDCM suggests that the more granular and cost reflective a charging methodology becomes, the greater the volatility and unpredictability of charges. This is because granular locational charges break up the network into small areas, within which the actions of a few generators could have a significant effect on charges. By contrast, less granular methodologies will tend to produce less volatile charges because the costs associated with any developments at a local level are 'smeared out' across the network as a whole.

The increased volatility of locational charges, combined with the fact that they are more difficult to understand and forecast, is likely to have two effects:

- First, it is likely to deter some would-be renewable generation customers from connecting to the HV and LV networks. This may be particularly true of LV domestic microgeneration, since households are less likely to have the expertise or the time and resources necessary to build up a thorough understanding of how distribution charges work or quantify the risks associated with their volatility. This in turn could act as a brake on growth in distributed generation capacity, even on those parts of the network that are demand-dominated. Because of this, careful consideration should be given to the effect that locational generation charges could have on the UK's ability to meet its 2020 renewable energy targets.[33]

- Secondly, locational charges would increase the risk of asset stranding. The logic for this is clear: the higher the degree of charging volatility, the greater the amount of risk that is loaded onto generation customers, and the greater the risk that existing generation customers will end up disconnecting from the network, thereby creating stranded network/generation assets.

As was noted in Chapter 4, in practice locational DUoS charges would constitute just one component of a suite of charging signals that generators receive. Depending on the form of the charging methodology introduced, other

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33 A further, related concern might stem from the fact that at least some existing distributed generators will have connected to the network with a business model that was based on the assumption of ongoing generation DUoS credits. A reform that replaced such credits with variable charges for these existing customers could undermine these business plans. Such unexpected changes to the established charging framework could make generation customers wary of the risk of further, unanticipated modifications, which could in turn discourage further growth in distributed generation capacity.

considerations and financial incentives (e.g., feed-in tariffs) could end up swamping any variation in locational DUoS signals. In this scenario, location charges may end up having little effect on the path of generation growth, the risk of asset stranding or the UK's ability to meet its renewables targets. However, as was noted in Section 6.2, this 'swamping' effect would also mean that customers would be unlikely to change their siting behaviour in response to locational charging signals, thereby undermining the key theoretical justification for introducing locational charges in the first place.

8 Annexe

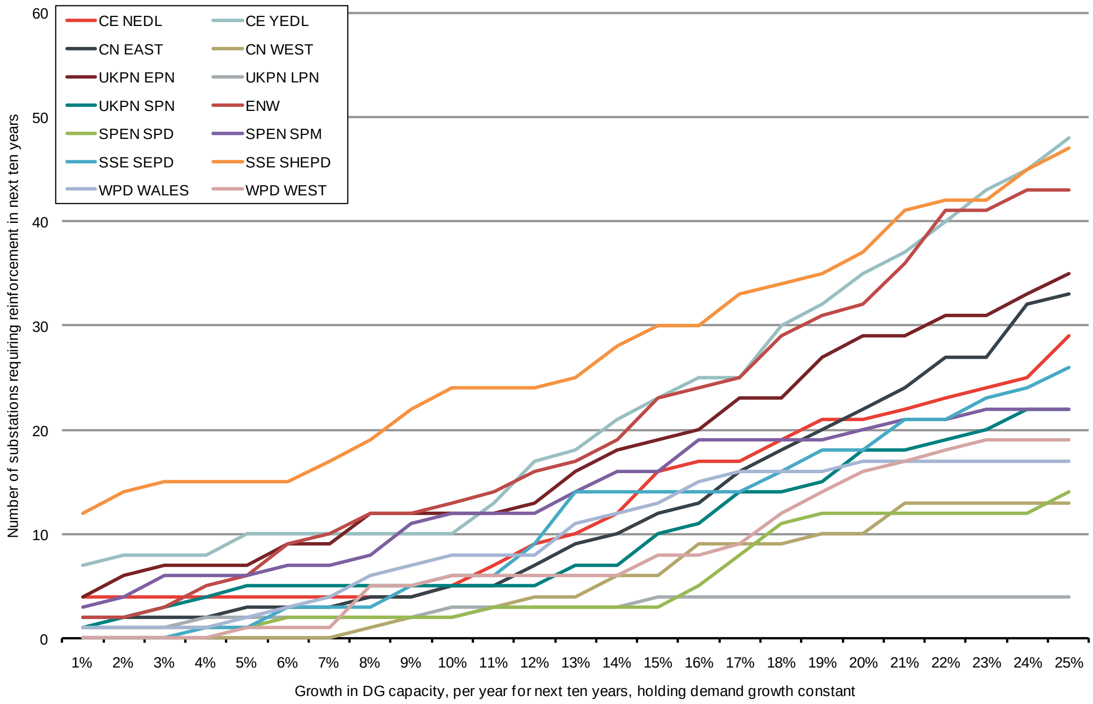
8.1 Further analysis of generation-dominated areas

Table 20. Number of GDAs identified by DNO area, generation growth type and rate

		Hot spot growth			*Even growth*		
DNO Area	**No. Primaries**	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
CE NEDL	196	4	6	17	7	10	10
CE YEDL	372	10	10	24	8	8	8
CN EAST	438	9	37	68	2	2	2
CN WEST	254	1	7	13	0	5	17
UKPN EPN	456	10	19	31	4	5	7
UKPN LPN	107	2	3	4	1	1	1
UKPN SPN	232	4	5	5	1	1	2
ENW	364	10	16	31	1	4	7
SPEN SPD	435	3	12	20	2	3	3
SPEN SPM	340	6	7	12	2	2	2
SSE SEPD	485	0	1	3	1	1	1
SSE SHEPD	427	19	30	45	77	103	124
WPD WALES	188	1	3	7	1	1	1
WPD WEST	322	0	1	6	0	0	0
Total	4,616	**79**	**157**	**286**	**107**	**146**	**185**

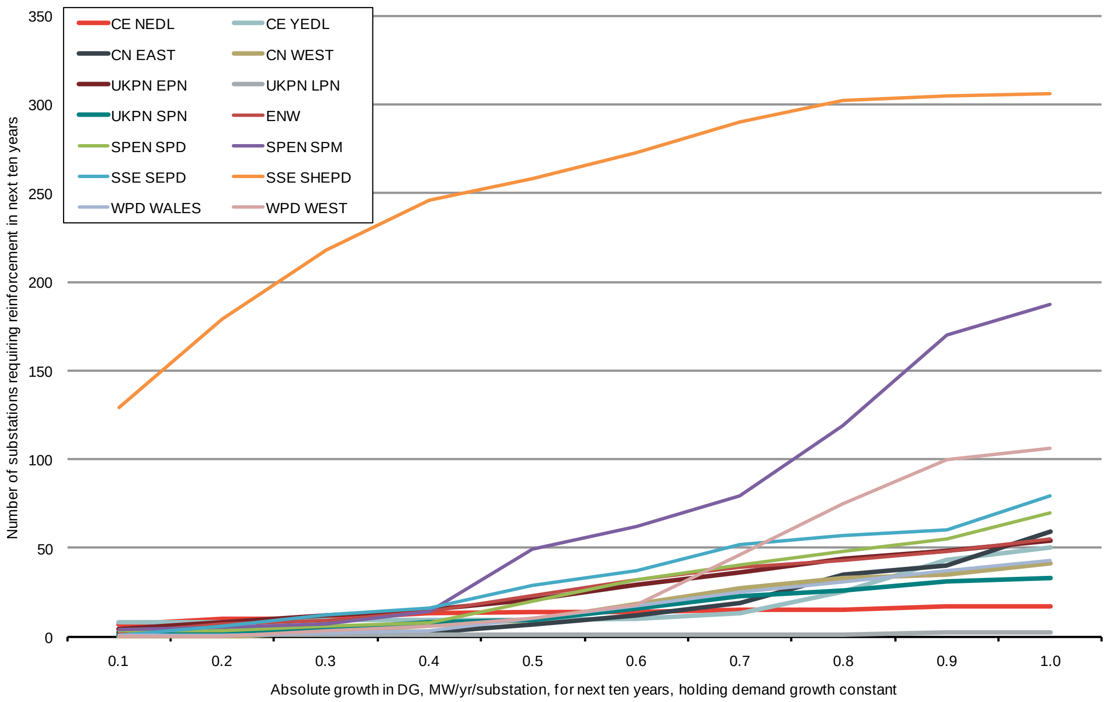
Source: Frontier Economics

Figure 19. Number of GDAs by DNO area as assumed percentage growth rate in generation increases



Source: Frontier Economics

Figure 20. Number of GDAs by DNO area as assumed absolute growth rate in generation increases



Source: Frontier Economics

8.2 DNO cost survey

Figure 21 shows a copy of the survey that we sent to the DNOs. It asked the DNOs about the costs of implementing and maintaining each of the three high-level locational charging options. For many of the questions we asked the DNOs to provide an answer in terms of the number of FTE days required. We then assumed that an FTE day costs £500 per day.

Figure 21. DNO survey

a) Methodology		
(i) How much do you think it would cost for the DNOs to jointly develop the new methodology?	Number of FTE days required across all DNOs	Number of FTE days
(ii) How much do you think it would cost for the DNOs to jointly maintain the methodology?	Number of FTE days required across all DNOs	Number of FTE days/annum
b) Data collection and manipulation		
(i) How much would it cost your DNO to collect the data and put it in a format that can be used in the methodology?	Total number of FTE days required within DNO group	Number of FTE days
	Others costs (e.g. measurement equipment). Please specify	£
(ii) How much would it cost to update this data every year?	Total number of FTE days required within DNO group	Number of FTE days/annum
	Others costs. Please specify	£/annum
c) Derive tariffs		
(i) How would you derive the tariffs e.g. spreadsheet or more complex IT system?		Descriptive
(ii) How much would it cost for the DNOs to jointly set up a new system to derive tariffs according to the options?	Number of FTE days required across all DNOs	Number of FTE days
	Hardware and software costs	£
	Other costs. Please specify	£
(iii) How much would it cost for the DNOs to keep the new system up and running (in addition to keeping the data up-to-date)?	Number of FTE days required across all DNOs	Number of FTE days/annum
	Hardware and software upgrades	£/annum
	Other costs. Please specify	£/annum
d) Generate invoices		
(i) How would the derived tariffs be converted into invoices?		Descriptive
(ii) How much would it cost to set-up a new IT system (or to modify the existing IT system) that generates invoices based on the derived tariffs?	Total number of FTE days required within DNO group	Number of FTE days
	Hardware and software costs	£
	Other costs. Please specify	£
(iii) How much would it cost to run the new (or modified) IT system that generates invoices based on the derived tariffs?	Total number of FTE days required within DNO group	Number of FTE days/annum
	Hardware and software upgrades	£/annum
	Other costs. Please specify	£/annum
e) Send invoices to suppliers		
(i) What would be the cost of setting up (or modifying) a system to send invoices to suppliers?	Total number of FTE days required within DNO group	Number of FTE days
	Other costs. Please specify	£
(ii) What would be the ongoing cost of sending the invoices to suppliers?	Total number of FTE days required within DNO group	Number of FTE days/annum
	Other costs. Please specify	£/annum
f) Resolve disputes		
(i) What would be the cost of resolving invoice-related disputes with suppliers?		£/annum
g) Other costs		
(i) Would there be any other set-up costs in addition to the costs detailed in a) to f)?	Other costs. Please specify	£
(ii) Would there be any other running costs in addition to the costs detailed in a) to f)?	Other costs. Please specify	£/annum

Source: Frontier Economics

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