Treatment of distributed generation

A REPORT FOR THE NMA

Introduction

1 Incentives for renewable energy resources have led to connection of significant numbers of wind power plants and combined heat and power (CHP) plants to the distribution networks in recent years and, despite the economic slowdown, this trend is expected to continue.

2 Frontier Economics has been engaged by Nederlandse Mededingingsautoriteit (NMa) to address a number of questions that relate to the treatment of distributed generation (DG), of industrial or commercial scale rather than residential scale, in the formula for allowed revenue. Specifically, NMa wishes to investigate the possibilities for better definition of the costs and benefits of DG.

3 In this report, we describe the background in more detail, we discuss the costs and benefits of DG and we conclude on the possibilities for an improved treatment of DG. We have structured the remainder of this report as follows.

a. **Background**. This section summarises the regulatory regime in the Netherlands, describes the previous method decision and the grounds on which it was challenged, and lists the key questions we have been asked to examine.

b. **Identification of the costs and benefits of DG**. This section summarises the costs and benefits occasioned by connection of DG, presents some stylised examples to illustrate the case-specific nature of the cost and benefits, describes the data that would be necessary to attribute network costs to demand users and DG users and concludes on the feasibility of identification of the cost and benefits of DG.

c. **Analysis and consequences**. This section notes the implications of the above, discusses the limited possibility of developing an improved treatment of DG based on an improved proxy for standardised output and summarises the results of a questionnaire issued to the distribution network operators (DNOs) seeking to understand the possibilities for developing this or other slightly more refined pragmatic approaches to the treatment of DG.

d. **Conclusions**. This section summarises our broad conclusions on the identification and allocation of the costs and benefits of DG and our reasoning taking account of responses to the questionnaire and comments made on the draft of this report. It

finishes by summarising our answers to three key questions posed in our terms of reference

4 This report seeks to avoid technical description as it is intended to be accessible to non-technical readers.

Background

5 In this section, we set out the background to our analysis of the options for treatment of DG. In turn, we summarise the features of the regulatory regime in the Netherlands relevant to the treatment of DG, we describe the previous method decision and the grounds on which it was challenged and we list the key questions we were asked to examine.

Regulatory regime

6 The key features of the distribution regulatory regime in the Netherlands are:

a. The allowed revenue for each DNO is determined on the basis of yardstick competition, effected through the application of an individual X factor for each company. The X factor is chosen to close the gap between the company's starting point and the industry wide efficient frontier. The industry wide productivity factor used to roll forward the price cap is based on the measured rate of change of the ratio of industry wide standardised output and total cost.

b. Prior to any adjustment implemented to account for DG, the volume component of standardised output is based on a set of outputs drawn from the elements of the tariff basket (i.e. the volumes for which final demand customers are actually charged). Each unit of output is then valued at the (volume weighted) industry average tariff for that element of the tariff basket. Since only demand customers are subject to distribution use of system (DUOS) charges (see below), standardised output captures only those deliverables to demand customers.

c. As a consequence of these arrangements, standardised output serves two purposes within the regulatory regime. First, it is central to the estimation of the underlying rate of productivity change in the sector as a whole as described above. Second, it "carves up" the total revenue that the sector is permitted to recover between the different DNOs, according to each company's share of total standardised output.

d. The regulatory regime recognises that the DNOs may not be sufficiently homogeneous to apply strict yardstick competition

without adjustment. Consequently, the arrangements include mechanisms to adjust allowed revenue to recognise

i. quality of service, through the q factor;

ii. regional differences in costs; and

iii. exceptional investments.

e. The distribution charging regime follows international practice and comprises both charges for connection to the distribution network and charges for use of the distribution network. Tariffs for DUOS charges must not exceed the price cap described above. At present, both demand users and DG users pay connection charges but only demand users pay DUOS charges

i. For connections up to 10MVA, connection charges are "shallow" in that a DG user pays the cost of connection to the nearest suitable network[1] regardless of whether sufficient capacity exists at this point and the connecting party makes no contribution towards the costs of any consequential reinforcement either locally or elsewhere on the network. For connections above 10MVA, connection charges are "deeper" in that a DG user pays the cost of connection to the nearest suitable local network where there is sufficient capacity but does not necessarily pay the cost of all remote reinforcement[2].

ii. DUOS charges to final customers for a particular DNO have no time or geographic variation but have voltage variation reflecting the notional use of the connected voltage tier and higher voltage tiers. There seems little appetite for introducing time and geographic variation[3]. Indeed, we understand there has been some debate as to whether all voltage tiers are necessary. The DUOS charges typically comprise up to five components: a fixed monthly payment (€), an annual contracted demand charge (€/kW contracted), a monthly or weekly maximum demand charge (€/kW maximum demand), an active

1 As defined in the Tariff Code.

2 Some remote reinforcement costs may fall initially on the DNO and, to the extent that are remunerated, will be recovered later through DUOS charges that fall on the generality of demand users.

3 Wider policy considerations may rule out geographic variation.

energy charge (€/kWh) and a reactive energy charge (€/kVArh).

7 Particular features relevant to the treatment of DG are:

a. With the exception of any specific allowance for regional differences and/or identification of special investments, the regulatory regime assumes that a unit of standardised output on average costs the same for all DNOs (i.e. that the DNOs are otherwise homogenous and differences in cost arise only as a consequence of differences in managerial efficiency).

b. The regulations oblige the DNOs to connect DG. However, as noted above, the DG does not always pay the full cost of its connection. For example, for connections up to 10MVA, the DG pays for a connection to the nearest suitable DNO line or substation according to a charge regime with variation by connection capacity, distance and voltage. The charge regime does not necessarily cover all connection costs, particularly if, for technical reasons, the DG is connected to a more distant line or substation or causes additional reinforcement costs locally or elsewhere in the DNO network. To the extent such additional reinforcement costs are remunerated, they are socialised either through future connection charges if a more distant connection is made or through future DUOS charges if reinforcement is required to allow connection to the nearest suitable line or substation.

c. The DNO may suffer stranded costs if the standardised output measure of DG falls as it has invested to provide network services but may not receive sufficient allowed revenue to recover the cost of these investments. (We note that while this is also formally true of demand it is potentially more problematic for DG. Demand sources such as residences are more likely to last 40 or 50 years than DG sources such as wind turbines or CHP plants.)

Previous method decision

8 The previous method decision, which has recently been overturned by the Dutch courts, treated DG in the following manner:

a. The formula for allowed revenue contained an additional term in respect of standardised output for DG.

b. This additional term comprised the sum over all tariff elements of the product of:

i. The DG volume, which was taken to be the higher of the maximum generation less the maximum demand at the point of connection or zero.

ii. The sector tariff, as imputed by the NMa, for the connection voltage tier and, broadly speaking, the next higher voltage tier[4] as it is argued that, typically, DG uses only these voltage tiers.

c. The sector tariff for a particular voltage tier was that which applies to demand users for the particular voltage tier, excluding the elements of that sector tariff cascaded from higher voltage tiers. It was determined as the difference between the sector tariff for demand users for the particular voltage tier and the sector tariff for demand users for the next higher voltage tier[5].

9 Although it was recognised that this approach was a simplification, it was adopted by NMa as

a. The association of DNOs, Netbeheer Nederland, had proposed the approach, albeit largely on pragmatic grounds in the absence of a better solution.

b. E-Bridge Consulting GmbH deemed the approach to provide a sensible solution to treatment of DG. Though, in its independent review of the proposal, E-Bridge Consulting noted that the approach:

i. Involved simplifications which might be challenged by some DNOs or third parties.

ii. Might be improved by making better estimates of the sector tariff for a particular voltage tier and of the use of higher voltage tiers, provided that supporting metering data were available and the additional administrative and resource burden of a more complex approach was reasonable.

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4 Sector tariffs were (and are) defined for the following voltage tiers: TS, HS/MS+TS/MS, MS-T, MS-D and MS/LS where MS-T represents a dedicated MS feeder with DG users only and MS-D represents an MS feeder with both DG and demand users. For DG connected at the low voltage side of HS/MS and TS/MS transformers, MS-T and MS-D, the sector tariffs related to two voltage tiers, the connection voltage tier and the next higher voltage tier. However, for DG connected at TS, the sector tariff related to a single tier, TS, and, for DG connected at the low voltage side of MS/LS transformers, the sector tariff related to three voltage tiers, HS/MS and TS/MS, MS-D and MS/LS.

5 So, for example, the sector tariff for MS-D was the sector tariff for demand users for MS-D less the sector tariff for demand users for HS/MS and TS/MS.

10 However, subsequently the smallest DNO, RENDO, challenged the decision on a number of grounds including:

a. **Competence of NMa to include a term in standardised output that is not at present charged for (i.e. the NMa's ability to impute a shadow charge for DG).** It is our understanding that the RENDO case has established an interpretation of the law under which the NMa is unable to include a term within standardised output where no actual charge exists. (We understand that the NMa is presently seeking to amend the law in this regard).

b. **Accuracy of cost-reflection of the method**. RENDO demonstrated several instances where the method decision did not reflect costs appropriately including:

   i. Incorporation of DG connection voltage tier and next higher voltage tier in the calculation of the DG costs. For some DNOs, the next higher voltage tier is that of another DNO (or TenneT) which accordingly bears any cost associated with the DG connection but does not get any revenue from the DNO in respect of such DG.

   ii. Distortions caused by the simple addition of the excess of DG above demand and demand to create standardised output so that a DNO with some DG may have higher standardised output than a DNO with no DG yet may face no additional costs.

   iii. Calculation of sector tariff at HS was based only on the HS assets owned by DNOs, not on all HS assets including those of TenneT.

   iv. Rescaling to ensure recovery of aggregate DNO costs was made at an aggregate level rather than by voltage tier which distorted the split of revenues among DNOs and as between connection and use of system charges.

c. **Failure to recognise benefits brought by DG**. Specifically, any reduced need:

   i. To contract with TenneT for transmission capacity[6][7].

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6 TenneT is unaffected as to the extent aggregate contacted or actual demand falls due connection of DG, it makes a compensating increases in its unit charges.

7 A recent change to the regulations deems transmission capacity payments to TenneT to be uncontrollable costs and thus largely removes any benefit in respect of new DG.

ii. To purchase energy in respect of distribution losses.

11 The Dutch court ruled in RENDO's favour on the grounds that, by law, costs related to DG cannot be allocated to tariffs charged to demand users through inclusion of the new term in standardised output but it was silent on the grounds relating to accuracy of cost-reflection and failure to recognise the benefits brought by DG.

Key questions

12 This successful challenge provides the context for three key questions we were asked to examine, namely:

a. What is, considering the data gathered by the DNOs, the highest possible level of quantification of the financial costs and benefits caused by DG?

b. What method should be used to reach this level of quantification, given the condition that it must be an objective method that can be validated against real data?

c. Will this method give a more precise description of the financial costs and benefits of DG than the model that the NMa used in the last method decision?

13 While these are the questions posed by our terms of reference, it is important to understand the context in which they were asked. In essence, the NMa wants a better understanding of the cost and benefits of DG that could be used to inform its treatment of DG. In any new treatment, there must be objective measures of the costs and benefits of DG. If the treatment is to be through developing a better measure of standardised output that can be used in the regulatory formulae, there are two key implications:

a. The measure of standardised output that reflects DG must be essentially an exogenous impact on the DNO and not something that is very substantially influenced by decisions of the DNO, as any measure of this latter type could provide perverse incentives that might distort behaviour.

b. In effect the standardised output needs to take the form of a ratio of total cost to the cost of serving an element of standardised output for which charges are levied. Standardised output derived from demand is not valued at a standardised cost of serving demand but at a standardised tariff which is designed to cover not only the costs of serving demand but also the cost of serving DG. Hence the value of any DG output needs to be similarly 'inflated'.

Identification of the costs and benefits of DG

14 In this section, we discuss the identification of the costs and benefits of DG under the following headings: costs and benefits of DG; practical examples; data considerations; and feasibility of identification of the cost and benefits of DG.

Cost and benefits of DG

15 The potential costs and benefits of DG are well known but the balance of costs and benefits depends on circumstances. We summarise the main costs and benefits occasioned by connection of DG below noting that a practical treatment of DG will need to deal with:

a. New and existing DG.

b. The choice between estimation of incremental or average costs and benefits of DG[8].

16 The main costs occasioned by connection of DG are:

a. Increased investment costs

i. To accommodate increased power flows. New DG will require a new connection to the network and may occasion investment elsewhere on the network to accommodate increased power flows.

ii. To address voltage issues. New DG will impact on local network voltages. This impact will vary on a case-by-case basis depending on spatial and temporal correlation between DG and local demand. If DG is connected to a feeder with existing load, the DG will tend to increase the voltage, thus improving the voltage at times of high load but, in the absence of other measures, possibly leading to excessive voltage at times of light load. The difficulties of addressing such voltage issues, particularly where the existing feeder has relatively little load, often mean that DG must be connected to a dedicated feeder[9].

iii. To address short circuit level issues. As connection of DG increases the potential current that can flow in the event of a fault, such as a short circuit, measures must be taken to ensure that all fault currents can be interrupted.

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8 Given the historical development of the networks to service demand users only, there is some argument that only incremental costs and benefits should be allocated to DG users.

9 In principle, the generator controls can regulate the voltage appropriately. In practice, such voltage regulation is costly and not sufficiently fast acting to deal with all possible voltage swings.

Such measures will vary case-by-case and may include replacing existing switchgear with higher rated switchgear[10], installing additional switchgear to limit current flow or installing series reactors to limit current flow. Where short circuit levels are already close to switchgear ratings, the cost of switchgear replacement may be high.

iv. To change protection. As distribution networks have traditionally been designed to deliver power from higher voltage tiers to lower voltage tiers with flow in a single direction, often the connection of DG requires changes of network protection to deal with possible reverse power flows and to ensure appropriate protection grading[11].

v. To provide necessary system redundancy to export DG. To ensure reliable export of power from a DG, there may need to be some network redundancy to allow for planned and unplanned network outages. Typically network planning standards require more secure connection of larger amounts of generation.

b. **Increased operating costs**. Connection of DG will increase both direct and indirect operating costs. The direct costs will comprise operation and maintenance costs associated with investments made to accommodate the DG. The indirect costs will include some increase in administration and other overhead costs.

c. **Increased loss costs**. The connection of DG may either increase or decrease energy losses. Again the impact will vary on a case-by-case basis depending on spatial and temporal correlation between DG and local demand. If the DG is connected to a long dedicated feeder, the energy losses on that feeder may exceed any reduction in energy losses elsewhere on the network.

d. **Increased operational complexity**. Insertion of DG in existing passive networks makes them active and hence more complex to operate. The cost consequence of this increased

10 Switchgear is rated by the maximum current that it can interrupt in the case of faults such as short circuits.

11 Protection grading is necessary to ensure that switchgear nearest to a fault, rather than more remote switchgear, operates to clear the fault, thus, minimising the number of network users affected by the fault.

operational complexity may not be apparent in the short term but are likely to become manifest in the medium term in terms of increased training and other staff costs.

17 The main benefits occasioned by connection of DG are:

a. **Delayed investment costs**. The connection of new DG with appropriate spatial and temporal correlation with local peak demand is likely to delay the need to reinforce the local network to accommodate load growth and, with appropriate temporal correlation with peak demand on higher voltage tiers, may also delay the need to reinforce the higher voltage tiers.

b. **Delayed operating costs**. There will be a consequential delay in operating cost increases if connection of DG delays investment.

c. **Reduced loss costs**. As noted above, the connection of DG may either increase or decrease energy losses. If the DG is connected to a short dedicated feeder, the energy losses on that feeder may be outweighed by reductions in energy losses elsewhere on the network. If the DG can be connected to a feeder with demand users, and its output is correlated with local demand and does not exceed twice that demand, the energy losses on that feeder will decrease and the energy losses on higher voltage tiers will also decrease.

d. **Improved system reliability**. With appropriate investment, new DG should increase system reliability because, although DG output may not be taken into account in system design, DG may be present at the time of a system incident and may reduce the impact of that incident. Such improvement in system reliability is likely to be relatively small but, over the long-term, may result in increased revenue to the DNO through its q factor adjustment.

18 Until recently, a further potential benefit to the DNO arose through reduced transmission capacity payments to TenneT. Specifically, the DNO retained any excess monies collected in respect of projected payments to TenneT, based on the yardstick of DNOs, if increased DG caused its actual payments to TenneT, which are based on demand less DG[12], to be lower than projected. However since July 2011, transmission charges have been deemed to be an uncontrollable cost which means that these charges are directly recovered from final customers so that there is now no possibility of excess monies accruing to the DNO[13].

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12 The TenneT charges are based on the annual contracted demand and the monthly maximum demands imposed on it by a DNO.

13 After taking account of forecast errors through application of correction factors and any influence that historical charges may have had on the setting of X factors.

Practical examples

19 Broadly speaking, the connection of a small amount of DG, which can be accommodated on an existing feeder, is likely to lead to a net benefit from delayed investment and reduction in losses but the connection of larger amounts of DG is likely to need a dedicated feeder and lead to a net cost. In the following, we illustrate the case-specific nature of the costs and benefits imposed by DG by considering a number of stylised examples:

a. **Wind farm cluster**. A typical wind farm comprises a number of wind turbines, sized between, say, 1MVA and 3MVA[14], with aggregate power output of, say, 10-30MVA, and sited at a windy (often coastal) location that is likely to be some distance from existing networks. The connection is likely to be through a long dedicated feeder denoted MS-T (see footnote 4). The opportunity to delay investment at higher voltage tiers is likely to be limited as wind generation is unlikely to contribute reliably to reduction in demand on higher voltage tiers at the time of the maximum demand on these voltage tiers. There may or may not be a reduction in energy losses on the network depending on the network circumstances.

b. **CHP cluster**. A typical cluster of CHP plants comprises a number of CHP plants, sized between, say, 1MVA and 3MVA, and sited adjacent to the heat demand and, thus, likely to be close to existing MS and LS networks. The connection is likely to be through a shorter dedicated feeder denoted MS-T. There may be an opportunity to delay investment at higher voltage tiers as the aggregate output of the CHP plants may contribute reliably to reduction in demand on higher voltage tiers, at the time of the maximum demand on these voltage tiers, despite planned and unplanned outages on individual CHP plants[15]. There may or may not be a reduction in energy losses on the network depending on the network circumstances.

c. **Individual CHP plant**. A single larger CHP plant is typically sized between, say, 1MVA and 3MVA, and sited adjacent to the heat demand and close to existing MS and LS networks. The

14 We understand that DG is usually sized to reduce the connection cost seen by the DG user. As the connection charging regime allows the DG user to be charged, in addition to an amount in respect of its direct connection, a contribution to the costs of sub-station if the connection capacity exceeds a particular MVA limit, DG users tend to size their units just below this limit.

15 Several DNOs note that CHP plants associated with horticulture tend not to contribute reliably at the time of peak demand. This is because the electricity production on the CHP plants follows the heat production which, in turn, depends on the market for the horticultural production.

connection may be through an existing feeder serving demand users denoted MS-D. The existing feeder network may have sufficient redundancy to allow the DG to export its power reliably but, equally, there may need to be reinforcement to the existing feeder network to allow the DG to export reliably. There is likely to be reduced opportunity to delay investment on the existing feeder and higher voltage tiers as the output of the single CHP plant will contribute less reliably to reduction in demand due to planned and unplanned outages. However, there is likely to be some reduction in energy losses on the network provided that the DG output is correlated with local demand and does not exceed twice that demand.

Data considerations

20 These stylised examples demonstrate that there is no typical DG installation and, accordingly, the costs and benefits of DG can only be estimated on a case-by-case basis.

21 The network stress imposed by a user depends on the circumstances, particularly time of use, location of use and voltage of connection.

22 It is usually possible to identify a new user that is responsible for some new network investment. In such cases, the (incremental or average) costs of investment and associated operation of the new capacity can be identified with a particular demand or DG user and, potentially, can be charged to that user as a connection charge[16]. Though, even in apparently simple cases, practical issues arise as, for example, the DNO may wish to install equipment of greater capacity than that required by the new user to use standard equipment sizes or to allow for future system growth.

23 It is not usually possible to identify the users that are responsible for all new network investment as, for example, investments to meet general load growth or to refurbish or replace existing assets cannot readily be attributed to particular users. Accordingly, the (incremental or average) investment and associated operating costs must be allocated and charged to the generality of network users as DUOS charges. Any allocation of these costs among users, and between demand users and DG users, is inevitably somewhat arbitrary and open to challenge.

24 It is significantly more difficult to identify the users that are responsible for investment and operating costs of the existing network. The user that drove the

16 Typically, the regulatory regime will control connection charges so that, strictly speaking, the particular user will be charged the allowed revenue in respect of the investment and associated operating costs of the new capacity. This allowed revenue may not cover all costs associated with the new capacity.

initial investment in a particular asset is unlikely to be known and, in any event, with system development the asset is now likely to have different users. Again, an (average) cost allocation will be required which is somewhat arbitrary and open to challenge.

25 One allocation methodology that has some theoretical merit is to allocate the costs of a network element to network users according to the stress that users place on the network element at the time of peak stress on that network element (in other words, charging users for their use of the network element at the time of peak use of the element so that demand users pay for normal flow through the element - imports - and DG users pay for reverse flow through the element - exports[17]). But there are many practical issues, such as: the intensive load flow modelling, resource and data requirements; the need to deal with spare capacity as, due to the need for system redundancy to allow for outages, most network assets are not fully loaded at the time of peak stress; the lack of data, such as time profiles of demand and DG, hence, contribution to peak stress on different network element and disaggregated historical investment costs; and the scaling to ensure appropriate revenue recovery. It is reasonably practical to allocate the costs of a network element based solely on direction of peak flow[18] but it is unlikely to be practical to allocate costs taking account of further spatial and temporal variation of flows.

26 It is easy to see that allocation of the costs of energy losses among users raises similar issues.

Feasibility of identification of the cost and benefits of DG

27 From the above, it is clear that it is not possible to identify the costs and benefits of DG unambiguously for many reasons. Further:

a. Any treatment of DG[19] is subject to challenge on the grounds that it is not adequately cost-reflective in particular circumstances.

b. Potential treatments that improve significantly on the previous method decision are likely to be data (and resource) intensive and the necessary data may not exist.

c. Potential treatments may not be stable as asset use and hence cost allocations will change with time.

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17 More precisely, from a system design perspective, the cost driver is demand if design has been to meet peak flow on the element which occurs at a time of peak demand with maximum reliable DG output and the cost driver is generation if design has been to meet peak flow on the element which occurs the time of maximum DG output for which demand is minimum.

18 Modelling can focus on just two critical conditions: the time of peak system demand with maximum reliable DG and time of minimum system demand with maximum DG.

19 Indeed, any treatment of demand.

28 In our initial discussions with the DNOs, the following points concerning the feasibility of identification of the costs and benefits were raised:

a. **The costing approach may be contentious.** The principal choice is between marginal costing (with some scaling to ensure average cost recovery) and average costing. These subjective choices may be contentious as they can lead to significantly different cost allocations.

b. **Judgement on the relative costs imposed by demand and DG will tend to be subjective.**

   i. **Investment costs**. In the case of existing assets, cost drivers are not readily identifiable[20]. In the case of new assets, while cost drivers might be identified at the time when the investment is planned, the cost drivers would likely change over time as the network develops. Further there may be gaming problems if a DNO has some discretion over whether to deem an investment to be driven by demand or DG.

   ii. **Operating costs**. Cost drivers of direct operating costs are less likely to be identifiable than those for investment costs. Accordingly, direct operating costs would probably need to be allocated based on some proxy driver such as in proportion to asset values. Indirect operating cost would also, of course, need to be allocated based on some proxy driver perhaps in proportion to direct operating costs.

   iii. **Energy loss costs**. In principle the impact of DG on energy losses can be estimated by load flow modelling. In practice, it would be difficult to determine the impact of DG, as opposed to other network investment, on distribution energy losses and the necessary modelling would be onerous, complex and probably contentious.

c. **The cost drivers for network investment tend to be local.** Demand is the cost driver on a line with an excess of demand over generation at the time of peak loading on the line; conversely generation is the cost driver on a line with an excess of generation over demand at the time of peak loading on the line. Hence, at lower voltages in particular where diversity (averaging) effects are less important, the cost driver is very local.

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20 And, for Westland, most costs now relate to existing investments and little new investment is likely in the medium term.

d. **The data to support more complex cost allocation are not likely to be available.** Current data collection is sufficient for current regulatory reporting but insufficient to support more complex costing. The DNOs collate limited physical and financial data on investment and operating costs. The DNOs do not classify costs by cost driver. For regulatory reporting, the DNOs provide:

   i. Investment costs divided into extensions and replacements by voltage tier.

   ii. Operating costs divided into purchase of transmission service from TenneT, own distribution operating costs, cost of energy losses, other direct costs, staff costs, taxes and interest.

e. **Any data collation costs must be reasonable.** The data required to support cost allocation must not impose an excessive administrative and cost burden. More complex cost allocations are likely to require more data and hence higher data collection costs.

f. **To the extent costs can be identified, there is scope for special treatment of DG.** The recently introduced special network expansion allowance – "uitbreidingsinvestering" (UI) - might potentially be used to provide a mechanism to remunerate DG[21]. The significant investment allowance – "aanmerkelijke investieringen" (AI) – seems unlikely to continue to provide a mechanism to remunerate DG as DG investment is unlikely now to be considered significant. In any event, we would expect the DNOs to prefer the UI mechanism as, with the UI mechanism, application must be made before the investment starts whereas with the AI mechanism application must be made only after the investment ends. The objective regional difference – "objectiveerbare regionale verschillen" (ORV) – might also be considered but, while DG volumes will vary regionally, there may not be any good reason why DG unit costs should vary regionally[22].

g. **If cost remuneration is based on network flows, DG use is more likely to result in stranded costs than demand use.** If

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21 At least for the regulatory period in which the investment is made.

22 We note that while connection of any particular type of DG may not vary regionally, differences could arise through mix of DG if there were differences between the typical costs of connecting wind and CHP, for example. However, it is not clear what these differences would be.

charges are based on network flows, the DNO will be exposed to stranded costs arising either through early closure of DG or through reduced flows in existing assets before the costs of the relevant assets have been fully recovered. In principle, early closure or reduced flows through demand user assets could also lead to stranded costs, though this is much less likely.

Analysis and consequences

29 After our initial discussions with the DNOs, we analysed the implications for this assignment, we considered the possibility of developing an improved treatment of DG based on an improved proxy for standardised output and we issued a questionnaire to the DNOs seeking to understand the possibilities for developing this or other slightly more refined pragmatic approaches to the treatment of DG.

Implications for assignment

30 We were sceptical that data existed to demonstrate that any alternative approach to the treatment of DG would be more cost reflective, and hence more robust to legal challenge, than the approach in the previous method decision.

31 Further, we considered that any attempt to demonstrate that an alternative approach would be more cost reflective would require a massive amount of analysis, potentially requiring detailed load flow analysis for each DNO's network to support cost allocations, and would be very expensive.

32 Indeed, we were not certain that we could identify any clear improvement to the approach in the previous method decision but, if pressed to identify improvement, we considered that we should focus on exploring the possibilities of a slightly more refined, but still pragmatic, approach to the treatment of DG. In particular, we should seek to identify an improved proxy for standardised output based on aggregate non-coincident maximum demand on each voltage tier as explained more fully below.

Improved proxy for standardised output

33 The existing regulatory system depends effectively on the presumption that the delivery of a unit of standardised output has a predictable cost which is on average very similar for all DNOs. In a network with demand users only, measures of customer load at a particular voltage level have predictable consequences for load cascaded up through higher voltage levels. Hence, there are predictable cost consequences arising from a given load.

34 The introduction of DG breaks this chain of predictable consequences. A mix of demand and DG users at a given voltage level can have very different consequences for the load that is imposed onto the next highest voltage level depending on the spatial and time correlation of the demand and DG. It is no

longer the case that a simple measure of what is served defines the cost of serving it. Not only will the relationship change but it can be expected to change differently in the circumstances of different DNOs and not to be stable over time.

35 Arguably, the best proxy for the volume of output at a particular voltage level would be some function of:

a. the aggregate non-coincident maximum demands measured at the downstream extremity of the voltage level (being either a connected load/DG or a step down transformer to the voltage level below);

b. the aggregate non-coincident maximum demands measured at the upstream extremity of the voltage level (ie on all feeders at the point they connect to the step up transformer to the voltage level above).

36 As noted, in a network with demand users only, the former measure can act as a proxy for the latter measure and hence standardised output can be described solely in terms of the former measure. In a network with both demand and DG users, this relationship not only changes but breaks down, suggesting that both measures are needed to create a proper measure of standardised output.

37 In principle, DNOs could be asked to make such measurements in order to construct a new composite for volume of output at a voltage level from a weighted average of these[23]. However, there were two problems with this approach:

a. It was almost certain that the DNOs would not have the required metering and installation of the required metering would be disproportionately expensive and, thus, impossible to justify.

b. It could lead to distorted behaviour as it would create inappropriate incentives because it would introduce into standardised output a measure that could be materially influenced by a DNO's own decisions on the way it plans its network development.

38 Therefore, we had severe doubts as to the practicality of this approach. Accordingly, we issued a questionnaire to the DNOs seeking to understand the possibilities for developing this or other slightly more refined pragmatic approaches to the treatment of DG. The questionnaire, set out in the annex to this report, explored what asset, operating cost and metering data might be

[23] Our intuition is that more weight would need to be given to the downstream aggregate of non-coincident maximum demands given the nature of network costs.

available to support improved methodologies for identification and allocation of the costs and benefits of DG.

DNOs' responses to the questionnaire

39 As the DNOs provided differing levels of detail in their responses, comparisons of the DNOs' responses were not always comprehensive or consistent. Nevertheless, we summarise below the DNOs' responses in certain key areas which inform our conclusions[24]:

a. **Identification of the costs of DG**.

   i. Liander and Endinet believe strongly that it is not possible to determine the costs of DG and demand other than by an (arbitrary and ambiguous) allocation.

   ii. Stedin perceives that the identification of costs is essentially a cost allocation issue and it considers that this is best done on a case-by-case basis.

   iii. Enexis states that any allocation will be nearly impossible and will always be arbitrary.

   iv. Westland can identify, and hence allocate to DG, the costs of investments made specifically for DG since 2005 but it cannot readily allocate the costs of investments made for both demand and DG since 2005.

   v. RENDO considers that it can identify the costs of new DG and for existing DG connected since 2003 on a case by case basis.

b. **Availability of asset and operating data to facilitate cost allocation by feeder (circuit)**. This informs the possibility of allocation of the costs of a network element based on flow through the element at time of peak stress on the element.

   i. Liander, Stedin, and Endinet cannot identify investment costs of assets by circuit.

   ii. Enexis can identify investment costs of a proportion of new assets by circuit (those considered as 'projects') but it cannot identify investment costs of existing assets by circuit.

24 We emphasise that this is just a summary of the responses received and does not include every response to every question. In reaching our conclusions we have, however, considered all responses received.

iii. Delta can identify investment costs of assets by circuit (it has a SAP information system that includes a circuit identifier for all assets above 10kV).

iv. Westland and RENDO can identify investment costs of recently constructed assets by circuit.

v. In general operating cost data is less disaggregated than investment cost data. For example, Delta can identify investment costs by circuit but cannot identify operating cost by circuit.

c. **Number of feeders importing or exporting at time of maximum flow**. This informs the possibility of approaches that allocate feeder costs to demand or DG based on flow direction.

i. Liander and Endinet state that data on numbers of feeders exporting and importing are available since 2009.

ii. Enexis state that additional metering would be required as existing feeder metering is for current magnitude only not direction of current flow.

iii. Stedin and Delta state that they cannot measure (presumably meaning that they do not have suitable metering at all necessary locations).

iv. Westland may not have suitable metering

d. **Identification of the cost driver for new investment**. This informs the possibility of allocating costs of new investment by driver.

i. Liander, Stedin, Enexis and Westland consider that the cost drivers cannot be identified unambiguously where investment is to serve both demand and DG.

ii. Endinet notes that the initial cost driver can be identified but considers it would not be fair to allocate costs based solely on the initial cost driver (as almost all its new investment is initially to serve demand but is later used to serve both demand and DG).

iii. Delta considers that cost drivers can be identified.

iv. RENDO considers that cost drivers can most likely be identified.

e. **Extent to which new investment is driven by objective application of planning and design standards or by other**

subjective factors. This informs the extent to which any new definition of standardised output might be manipulated.

i. Liander and Stedin claim that application is fully objective

ii. Endinet notes that some subjective factors are important

iii. Delta notes that many subjective factors are important and its wider comments suggest that application of standards can be further influenced by strict interpretation of the law and Tariff Code.

iv. Westland notes that the demand forecast is an important subjective factor.

v. RENDO states that application is not fully objective.

f. **Improved methodology for allocating costs to DG and demand users**.

i. Liander and Endinet advocate the search for an objective and plausible means of cost allocation. They consider that the previous methodology represents a good starting point for such an allocation

ii. Westland does not understand how a new definition of standardised output (setting the measure of standardised output as some function of the aggregate non-coincident maximum demands at the downstream and upstream extremities of a feeder) would improve on the previous methodology.

Conclusions

40 In this section, we draw broad conclusions on the identification and allocation of the costs and benefits of DG taking account of the responses to the questionnaire and comments made on the draft of this report. Then, we summarise our answers to the three key questions posed in our terms of reference.

Feasibility of developing an improved methodology

41 We draw the following broad conclusions. We consider that:

a. The **key issue is more one of cost (and benefit) allocation rather than cost (and benefit) identification** as the costs (and benefits) of DG cannot be identified unambiguously except perhaps for the costs (and benefits) of some new and recently constructed assets for which the cost driver is known.

b. **Any cost allocation would require some allocation rules** which inevitably will be subject to interpretation, will not cover all situations and will be subject to challenge. For example, rules would be needed to deal with:

   i. Existing assets for which the cost driver is not known.

   ii. Change of cost drivers over time.

c. **The data to support the appropriate cost allocation are not available at the requisite level.** Any cost allocation must be objective and neither cost data nor output data are currently available at feeder (circuit) level. The responses to the questionnaire show that:

   i. Investment and operating costs cannot readily be identified by feeder by any DNOs except, perhaps, Delta.

   ii. Additional feeder metering would be required to determine whether demand or DG is the cost driver for the feeder by all DNOs except Liander. This cost of such additional metering is unlikely to be justified.

d. **A DNO would likely be able to influence to some extent the measure of its standardised output** and, in particular, the balance between standardised output relating to demand and DG by its subjective decisions on network development. We do not believe that planning and design standards can be applied completely objectively to determine network investment not least because the appropriate network investment depends on projections of demand and DG.

e. **A simple pragmatic approach to the treatment of DG should continue** to be followed as,

   i. A more theoretically correct approach based on allocation of network element costs based on flow through the element at time of peak stress on the element is not practicable at reasonable cost.

   ii. Given the current regulatory framework, we doubt that there is any methodology which will not be subject to legal challenge.

Key questions

42 To summarise, we have significant doubts as to the feasibility of developing an improved methodology for treatment of DG that would not be subject to legal challenge. Our responses to the key questions posed by our terms of reference are:

a. **What is, considering the data gathered by the DNOs, the highest possible level of quantification of the financial costs and benefits caused by DG?** In principle, quantification of costs and benefits of DG can be at any level of detail because quantification boils down to an allocation of cost and benefits[25]. In practice, quantification can only be at a higher level than is useful.

b. **What method should be used to reach this level of quantification, given the condition that it must be an objective method that can be validated against real data?** We cannot recommend an improved method that would not be subject to potential legal challenge. Lack of appropriate metering and disaggregated accounting data mean that we cannot propose an improved method either based on an improved proxy for standardised output or based on allocation of costs and benefits at a circuit level. In principle, an allocation method can be made objective in the sense that the allocation is completely mechanical based on real data inputs[26]. However, in practice, an allocation method based on real data will be limited to an allocation at an aggregated level and, accordingly, the method will inevitably not be appropriate to particular circumstances which require a greater level of quantification[27].

c. **Will this method give a more precise description of the financial costs and benefits of DG than the model that the NMa used in the last method decision?** It will require extensive analysis to determine whether any revised methodology usually reflects costs (and benefits) of DG more accurately than the methodology in the previous method decision. Even with extensive analysis, it will be impossible to prove that a particular methodology gives more accurate results than the previous methodology in all circumstances[28]. Accordingly, we do not believe that such analysis would be worthwhile.

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25 As most assets are associated with provision of network services for both demand and DG users and the costs of such assets cannot be identified unambiguously with either demand or DG users.

26 Provided that the allocation method is based on data that cannot be influenced by the DNO.

27 The cost impact of DG penetration on a particular circuit is not linear. Thus, if the cost impact of DG is represented by a cost allocation method based on the proportion of DG at DNO level or grid connection point level, rather than at circuit level, there will inevitably be anomalies.

28 As any analysis can only compare a limited number of cases. Any such analysis would inevitably be somewhat subjective given the need to choose cases for examination.

43 While it will not be possible within practical limits to develop a methodology for treatment of DG that can be shown to be objectively superior to that in the previous method decision, it might be possible for the DNOs to agree changes to the previous methodology that they would regard as improvements (even if external verification that the changes were indeed improvements could not be provided).

Annex: Questionnaire issued to the DNOs

Introduction

1 This questionnaire concerns the feasibility of possible methods to identify and allocate network costs to distributed generation (DG) and demand.

2 We need to test whether data exist, or could be prepared, at a sufficiently disaggregated level to allow identification of the costs and benefits of DG. We would appreciate if you would:

a. Indicate your views on the practicality of identifying and allocating costs at a disaggregated level.

b. Provide information on the background data, asset data, operating cost data and power flow data that your distribution network operator (DNO) holds or could collate.

3 **We stress that, in many cases, we are seeking to establish whether data exist or can be readily prepared rather than requesting the data itself**. We anticipate that not all these data will exist or can be readily prepared.

Questions

Practicality of cost identification and allocation

4 We consider that more robust options for addressing DG may need to identify and allocate investment and operating costs by geographic region or circuit or even asset between DG and demand.

a. What data are available to support such an approach?

b. What additional data would need to be collected?

c. What would it cost to collate the required data?

d. How would you approach such an allocation?

Background data

5 What is the coincident maximum demand (MW) on your network for the most recently available year?

6 What is the connected capacity (MW) of DG on your network for the most recently available year?

7 What is the number of km of overhead line and km of cable at each voltage level on your network for the most recently available year?

8 What is the number of MVA of transformer capacity for each transformation level on you network for the most recently available year?

9 Are the following data available or could they be prepared readily:

a. The coincident maximum demands (MW) and annual energies (MWh) in aggregate and at each voltage level on your network for each of the last five years;

b. The non-coincident maximum demands (MW) at each voltage level on your network for each of the last five years;

c. The connected capacity (MW) of DG in aggregate and at each voltage level on your network for each of the last five years;

d. The number of km of overhead line and km of cable at each voltage level on your network for each of the last five years-;

e. The number of MVA of transformer capacity for each transformation level on you network for each of the last five years; and

f. The number of distribution feeders that exported power from the feeder and the number of distribution feeders that imported power to the feeder, at the time of peak flow on the feeder, at each voltage level, in each of the last five years.

Asset data

10 What proportion of the net book value of assets on your asset register are operational (e.g. line and substations) and what proportion are non-operational (e.g. office buildings)

11 What is the lowest level of disaggregation of existing MS, TS and HS assets on your asset register? For example,

a. Can investment costs of individual items of main equipment such as lines, transformers and circuit breakers be identified?

b. Can investment costs of existing assets be identified by circuit?

c. Can investment costs of existing assets be identified by geographic region?

d. Can investment costs of existing assets be identified by voltage level?

Operating cost data

12 What is the highest level of disaggregation of direct operating costs in your management accounting information? For example,

a. Can operating costs of individual items of main equipment such as lines, transformers and circuit breakers be identified?

b. Can operating costs of existing assets be identified by circuit?

c. Can operating costs of existing assets be identified by geographic region? and

d. Can operating costs of existing assets be identified by voltage level?

Circuit flow data

13 What metered data are available on MS, TS and HS circuits?

a. Are both import and export of both MW and MWh measured at each voltage level?

b. Is the time of any maximum demand of MW metering recorded?

c. What is the integration interval of MWh metering?

d. Are these meter data stored locally (at the substation) or remotely (at some central location)?

14 Can MW and MWh losses be measured by voltage tier and, if so, how?

15 Does objective application of planning and design standards determine new investment or are other judgemental factors important?

16 Can the cost driver (i.e. whether DG or demand) be identified for each new investment?