The evolving role of the DSO in efficiently accommodating distributed generation

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ECN-E--07-063

June 2007
Acknowledgement
This document is a deliverable of Work Package 3 of the DG-GRID research project, entitled: ‘Analysis of DG costs and benefits and the development of grid business models’.

We thank our DG-GRID colleagues, in particular Ding-Mei Cao (Imperial College London), Tomás Gómez and Pablo Frias (University Pontificia Comillas), Seppo Kärkkäinen (VTT), Uwe Leprich (IZES), Dierk Bauknecht (Öko-Institut), Stephanie Ropenus and Klaus Skytte (RISØ National Laboratory) for inputs to this report.

The DG-GRID research project is supported by the European Commission, Directorate-General for Energy and Transport, under the Energy Intelligent Europe (EIE) 2003-2006 Programme. Contract no. EIE/04/015/S07.38553. The sole responsibility for the content of this document lies with the authors. It does not represent the opinion of the Community. The European Commission is not responsible for any use that may be made of the information contained therein.

Project objectives
The objectives of the DG-GRID project are:

• To review the current EU MS economic regulatory framework for electricity networks and markets and identify short-term options that remove barriers for RES and CHP deployment.
• To analyze the interaction between economic regulatory frameworks, increasing volume share of RES and CHP and innovative network concepts in the long-term.
• To assess the effects of a large penetration of CHP and RES by analyzing changes in revenue and expenditure flows for different market actors in a liberalized electricity market by developing a costs/benefit analysis of different regulatory designs and developing several business models for economic viable grid system operations by DSOs.
• To develop guidelines for network planning, regulation and the enhancement of integration of DG in the short term, but including the opportunity for new innovative changes in networks in the long-term

Project partners
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• Institute for future energy systems (IZES), Germany
• RISØ National Laboratory, Denmark
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Abstract
This report investigates the evolving role of the distribution system operator (DSO) regarding the efficient access to and integration distribution networks of distributed generation. It investigates the business environment for DSOs shaped importantly by the regulatory framework to which the DSO is subjected. The focus is on cost impacts for DSOs of their provision of access to increasing volumes of distributed generation (DG) to their networks by DSOs and the contractual relationships between the DSO and DG operators. Moreover, the report describes opportunities for DSOs and DG operators to become involved in the delivery of ancillary power system services. The report concludes with recommendations on new broad directions for network regulation that will better align the profitability of the DSO business to their provision of socio-economically efficient network services and to a paradigm shift from passive towards active network management practices.
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Glossary of abbreviations and essential terms

AC  Alternating current
ANM  Active network management
AS  Ancillary services
BRP  Balancing responsible party
CAPEX  Capital expenditures
CAPM  Capital asset pricing model
CCGT  Combined Cycle Gas Turbine
CF  Cash flow
CHP  Combined heat and power production
Connection charge  A connection charge is paid on a one-off basis to DSOs by producers and consumers when a physical connection to the network is realized. Typically, it is a charge for the initial connection to the grid to be paid by both generators and consumers. The upgrade and renewal of the connection is usually not regarded as part of the connection charge but show up as administrative costs in UoS charges (see below). It depends on the EU member state whether or not connection costs are regulated.
DER  Distributed energy resources
DFIG  Doubly-Fed Induction Generator
DG  Distributed generation
DSO  Distributed system operator; also referred to as distribution network operator (DNO) in the UK
EU  European Union
GO  Guarantee of Origin
GSP  Grid supply point
HV  High voltage
IBR  Incentive-based regulation
ICT  Information and communication technology
LV  Low voltage
MS  Member state (of the European Union)
MV  Medium voltage
MW  Megawatt
MWh  Megawatt hour
NPV  Net present value
O&M  Operation and maintenance costs
OCGT  Open cycle gas turbine
OPEX  Operational expenditures
PNM  Passive network management
RAB  Regulated asset base

Smart metering  Metering the volume of electricity injection into, or ejection from, a DSOs network at the customer’s end in a way enabling at least automatic meter readings for billing purposes and distributed generators and consumers to be informed about their electricity feed-in or consumption over short time intervals. In more sophisticated implementation modes smart metering also enables through bi-directional communication between a central control agent and intelligent devices attached to meters at the customer’s end third-party remote control options for generation of ancillary system and automatic demand response options.

TAS  Transmission-system ancillary services

TOTEX  Total expenditures

TSO  Transmission System Operator

UoS  Use of system

UoS charges  Use of system charges are paid by generators and consumers (or their suppliers for small consumers) to DSOs on a periodic (e.g. per annum or per month), capacity (per kW peak or kW connected) or volumetric (per kWh) basis for the use of the “grid”, i.e. the public transmission and distribution systems, in transporting electricity to customers. UoS charges encompass both the service of transport of electricity and complementary system services. UoS charges represent the main revenue stream to DSOs, with their levels normally being regulated. Typically the regulator aims to allow DSOs a reasonable return on their assets, while at the same time encouraging them to improve operating efficiency along with meeting quality of service standards. In some EU member states generators do not have to pay UoS charges.

WACC  Weighted average cost of capital
Summary

This report seeks to outline the role in store for distributed system operators (DSOs) in Europe in the medium-term future in furthering efficient penetration of distributed generation (DG) in electricity supply systems. As the core business of DSOs, to provide their customers with quality network services at lowest cost, is regarded to be a natural monopoly DSOs are typically subject to tariff regulation. Moreover, for that reason the European Commission advocates an effective separation of DSOs providing network service activities from commercial activities related to the production of and trade in electricity.

Traditionally the most important customers of DSO business entities are the final electricity users connected to their grids. The DSOs use to wheel electricity originating from large-scale power plants connected to the high-voltage grid operated by the Transmission System operators (TSOs) concerned. Lately, in the wake of emerging trends towards rising levels of distributed generation DSOs have to put more and more effort in accommodating distributed generators. In doing so, DSOs have to absorb distributed generation fed into their networks and transport it either to end users connected to their own network or, in reverse mode upstream, to the pertinent high-voltage TSO network. DSOs are mandated to provide these services, although they pose significant technical challenges to them. Evidently, evolving regulation regarding distribution networks sets the key framework conditions governing the business behaviour of European DSOs in coping with these challenges.

Current regulation of distribution system operators (DSOs) by EU member states does hardly allow for network integration of distributed generation (DG). It does not address the issue of integrating rising levels of distributed generation in system operation. Moreover, it does make too little allowance for the cost impacts thereof for the DSO and for the (potential) benefits of DG for active management of distribution networks. This, in turn, may entail aversion on the part of DSOs to readily facilitate the network integration of new DG plants and may as well inhibit the adoption of efficient active network management (ANM) practices. Active as against passive network management seeks to integrate distributed generation assets as active components in their operational management of their network. To be able to do so, an enabling upgraded network and concomitant ICT infrastructure is warranted as well as an enabling regulatory framework and mandatory or commercial contracts between DSOs and distributed generators. On the other hand, holding on to passive network management may imply higher than optimal network costs and, consequently, higher network charges to the end users.

In order to investigate the future role of DSO in facilitating distributed generation, two future DSO business models are elaborated based on a baseline regulatory policy scenario and an alternative policy scenario fostering ANM. Both scenarios have common components such as:

- An articulate competition policy fostering the emergence of a single European electricity market marked by a complete unbundling of regulated network activities from liberalised activities such as generation, wholesale trade and retail supply.
- Enduring support for DG.
- Large-scale roll-out of smart metering consistent with the option of remote control of loads by DSOs and third parties.

DSOs are only likely to be enticed to embrace an ANM-type of business model by the concurrent implementation of a broad package of regulatory reforms. Reasons are the complexity of the ANM practices and the demanding requirements with respect to quality of service facing the DSOs. Therefore, the alternative policy scenario differs from the baseline scenario among others regarding:
Stimulation through appropriate sticks and carrots of the introduction of smart network tariffs with time- and location-differentiated use-of-system charges.

Smart design of DG support mechanisms.

Facilitation of the recovery of justifiable IT-related cost warranted by ANM.

Facilitation of other justifiable incremental costs related to the rise of DG (see hereafter).

The report takes a special look at the opportunities for DG and DSOs to create value through the provision of a range of ancillary power system services by DG. It concludes that the scope for revenue-enhancing provision of ancillary services by DG appears limited. Most scope seems to be in store for the provision of secondary and tertiary frequency regulation services to the TSO aided by DG aggregating actors as well as localised services such as the provision of reactive power and voltage support services. Adoption of ANM may improve the prospects for DG to deliver local ancillary services to their DSO.

Departing from a specific base case incentive-based regime, the report identifies broad directions for reform of DSO network regulation along the following avenues:

- Allowance for DG in the regulated asset base (RAB) and allowable OPEX.
- Allowance for DG by way of a new component in quality of service performance regulation.
- Allowance for DG through including of a factor in the productivity benchmark analysis.
- Allowance outside the benchmarking procedure (z-factor).
- Allowance for DG in a network-specific adjustment factor.
- Allowance for DG by way of direct revenue driver.
- Shift from building blocks approach (with distinct treatment of allowable capital expenditure and operating expenditure) to the TOTEX approach (which directly regulates total expenditure).
- Shift from frontier benchmarking to average benchmarking.
- Shallow connection charges in tandem with time-variable UoS charges with locational signals.
- Responsibility for DSO of distribution losses with time-variable carrots and sticks.

Finally it is noted that overall the DG GRID project has produced valuable new insights into regulation of DSOs. Yet in the framework of DG GRID no integrated analysis of the social net benefits of further penetration of DG was envisaged. Hence the question how far the penetration of DG should go from a societal perspective remains to be addressed. DG and notably renewables-based DG has significant externalities such as greenhouse gas emission mitigation and mitigation of long-term energy supply security risks. Yet DG GRID research results suggest that at high levels of DG penetration the incremental network costs can become quite large. Hence, depending on a range of conditions in the network service area it might well be that a certain socially optimal penetration level for DG exists. The design of DG market stimulation instruments can have an important bearing on this. The optimal design of DG stimulation mechanisms should make due allowance for the time-variable impact on network integration costs. These issues call for an integrated cost-benefit analysis of DG. On the cost side, to establish just the comparative economics of distributed generation alone is not enough. The costs of network services needed to deliver the produce of DG power plants to the end-user should be included in the comparison between alternative electricity generation technologies. Such analysis could lead to new insights and relevant policy prescriptions regarding both DG stimulation policy and network regulation regarding the price of network services rendered to DG customers.
1. Introduction

1.1 Background

The design and operation of current electricity systems is challenged by increasing penetration of sustainable electricity generation in the overall electricity generation portfolio. Within the European Union (EU) sustainable electricity generation is supported by national governments in order to attain longer-term sustainability targets. An important part of new electricity generating units is small-scale and is interconnected to the distribution system (at distribution system voltages) that are operated by distribution system operators (DSOs). Examples of these small-scale units are single wind turbines, photovoltaics, small biomass, small hydro units and small combined heat and power (CHP) units.

The vibrant growth of DG changes the nature of the distribution network. Whereas it formerly served to transport electricity from the higher voltage transmission network towards end-consumers connected to the distribution networks, the distribution network is now used more and more to attune localized supply to local demand. This fundamental shift entails opportunities and challenges to the DSO. For example, it can pose difficulties for operational load flow management (balancing) and create new investment requirements. On the other hand, it can:

- Reduce distribution losses.
- Defer investment in reinforcements of higher voltage networks.
- Create opportunities for the DSO to procure local ancillary services at lower costs than is the case when providing these internally.
- Create opportunities for the DSO to act as a mediator for the DG operators in the market for TSO-arranged ancillary services.

1.2 Research focus

Although a large volume of literature is available on the possible impact of an increase of the share of DG in electricity systems on sector efficiency, performance and society, it seems that the role of the DSO to that effect is rather underexposed. From a societal point of view the total benefits of distributed generation may well outweigh total costs, yet the allocation of private costs and benefits would seem to be unevenly spread among the relevant market actors. In turn, this may prompt market actors to conduct socially suboptimal business practices.

In particular, the question arises as to whether the DSO is sufficiently incentivised to facilitate further development of DG in the face of current regulatory constraints. If not the case indeed, this raises the next question, that is, which changes in regulatory arrangements do effectively stimulate DSOs and DG operators to collaborate efficiently in furthering and accommodating a rising penetration of DG in a socially benign fashion? This report starts to address these questions in a primarily qualitative way. It seeks to analyse the type of arrangements that currently exist between the DSO and DG operators and what type of arrangements could become reality in the future.

In this report we investigate how an increasing penetration of DG in distribution networks can impact upon the overall business model of the DSO. What are the opportunities and threats to

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1 Also security of supply considerations plays an important role in the support for renewable energy technologies. An increasing use of renewable energy reduces fossil fuel dependence (e.g. oil and gas) and reduces market vulnerability for interruptions in fossil fuel supply.

2 Companion DG GRID report D10, (De Joode et al., 2007), applies spreadsheet projections of quantified DSO business models to yield further insights into these issues.
the DSO created by this development and what are possible directions for improving the regulatory environment. The current regulatory framework might need to be adjusted to give DSOs the ability to deal with threats and seize business opportunities that at the same time have socio-economic benefits. So far, DSOs practise passive network management (PNM) relying on robust network reinforcement to avoid congestion and other technical network problems even under rather extreme network conditions rather than relying on DG facilities when having to cope with such conditions. Given increasing rates of penetration of DG and concomitant increasing complexity of network management, this operational philosophy is set to become overly expensive and increasingly cumbersome. However, the adoption of active network management (ANM) which seeks to actively deploy DG and flexible demand services provided by end users to relieve network problems warrants a paradigm shift on the part of network operators and adjustment of the regulatory framework.

Hence our main research questions are:

i. What is the role of the DSO in furthering efficient penetration of distributed generation?

ii. How does DSO regulation accommodate the DSO to play a major positive role towards that end?

With sub-questions being:

- What is the impact of rising DG penetration on current DSO activities?
- What are the opportunities for future DSO activities under prevailing regulatory frameworks which presume PNM practices?
- How would adoption of ANM practices affect the DSO business model and the DSO relationships with direct DSO business partners?
- Can provision of ancillary services by DG become an additional revenue driver for the DSO?
- What broad directions for adjustment of regulatory frameworks governing DSOs in the EU would be warranted to induce DSOs to embrace ANM as their guiding operational philosophy?

1.3 Report structure

The structure of the remainder of this report is as follows. In Chapter 2 we describe current DSO business models and network regulation in the EU in both theory and practice. Prospective developments regarding contractual arrangements between the DSO and counterpart actors, especially DG operators, are analysed and stylised in Chapter 3. Chapter 4 highlights the roles for DG and DSOs in the provision of ancillary network services. Chapter 5 reviews regulatory changes in a number of key aspects that would enable the DSO to facilitate a more socially propitious future development of DG.
2. Current DSO business models and regulatory frameworks

2.1 DSO business models prevailing in EU member states

Contemporaneous business models stylizing the business of a European DSO are taken as point of embarkation for the analysis in this chapter. A DSO business model identifies the major incoming and outgoing financial streams (revenues and expenditures) of a DSO and brings out the contractual relationships of the DSO with other electricity market actors.

The typical DSO's position in relation to other stakeholders in current EU electricity markets can be briefly described as follows, considering the income and expenditure side of the DSO successively. The DSO provides different services to users of the DSO network, i.e. final electricity consumers and distributed generators. Users of the DSO network pay for both the transport and complementary system services, taken together in so-called use of system charges, as well as for their connection to the network.

A connection charge is paid when the connection to network is realised and can be considered as an ‘investment’ type of charge. Three distinct approaches of calculating connection charges can be distinguished: shallow, deep and shallowish charges. Shallow connection charges include only the cost of connecting the customer to the nearest point in the distribution network. The costs of additional network reinforcements are not included in these charges. As opposed to shallow connection charges, deep connection charges contain the costs of network reinforcements both at the transmission and distribution level as well as the direct connection costs. Shallowish connection charges as applied in the UK, are a mix of both approaches as they contain both direct connection costs and costs for the proportional use of reinforcements at the distribution level.

For providing fair and non-discriminatory network access to the network for different kinds of generators, including small DG units, it is important to introduce shallow or shallowish connection charges. This avoids large upfront costs for DG, which would discriminate against DG as compared to centralised generation. Besides, this kind of connection charges lowers transaction costs to DG by keeping the calculation straightforward and transparent and avoiding negotiations about the “deep” connection cost component. From the point of view of DSO, however, this is not a favourable option if the costs of network reinforcement due to DG are not covered in some way. Therefore, it is recommended to socialize the incremental grid reinforcement cost among network users by way of use of system (UoS) charges.

UoS charges are levied for both the electricity transport from the sources of production to the end users and for the additional system services needed for ensuring secure, high-quality network services. UoS charges can be based on the end user’s energy consumption (kWh), his system capacity requirement (kW contracted or kW peak), levied as a fixed periodic rate or as combination of the former three components. Usually, a difference is made between the charges/tariff structure of transport services and system services. Whereas the charges for system services are immediately passed through to end-users (as a surcharge per kWh consumed), for the provision of transport services typically cascading transport tariffs are applied. This implies that the transport tariffs to which end users are subjected, include a transmission network component even if the actual source of production is a nearby distributed generation facility.

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3 See Werven and Scheepers (2005) and DISPOWER (2006) for a more elaborate description. This section describes current practises. In the next chapter we will elaborate on possible future DSO business models.

4 See Skytte and Ropenus (2005a) and papers published under the EU supported research projects ELEP (Knight et al. 2005) and SUSTELNET (Scheepers, 2004).
In principle, UoS tariffs charged to generators should differentiate in accordance with specific characteristics of generators. A major differential incremental impact upon network costs can be occasioned, among others, by the location of the distributed generator and the network level of the latter’s interconnection with the distribution network. The location of generators may determine whether, and if so how much, network reinforcements and upgrades are necessary. For example, wind power is often situated at the end of the network far away from load centres and may therefore imply relatively more network reinforcements than generators located closer to load centres. These network effects may be internalized by giving some locational signal to generators. With regard to the network level, due to its generally relatively small and dispersed character DG is able to reduce network losses (on all network levels) up to a certain point, and can postpone or avoid higher voltage-level network reinforcements.

For the DSO being able to provide connection, transport and system services and to levy charges, specific expenditures have to be made. In case of connection costs a part of the network has to be disconnected in order to accomplish a physical connection of the consumer to the network. Concerning transport costs, expenditures may have to be incurred to relax transport restrictions by way of reinforcements and upgrades of the network. Moreover, higher utilisation levels of lines (and cables) increases line losses more than proportionally. The DSO may or may not be incentivised to reduce losses incurred on his network. There are two possible incentive mechanisms. First, DSOs may have to meet specific network loss targets and, by implication, are rewarded (penalized) for (not) meeting them. Secondly, DSOs may be obliged to make up for energy losses through procurement of corresponding quantities at the market. In member states where no incentivisation prevails, the TSO will take care of procurement to cover these losses and include the losses procurement costs fully in the system services charges to final consumers (see below).

System-wide ancillary services to ensure the reliability and quality of electricity supply are managed by the TSO. Examples are: maintenance - and in the event of deviations restoring - the energy balance; solving large power interruptions; providing frequency control; and ensuring black start capabilities. These services are most commonly summarized under the heading of congestion management. Localised ancillary (system) services such as local voltage control and reactive power are typically delegated to the DSO. For large power consumers connected to a particular DSO grid, the DSO collects system services charges on behalf of his TSO. In turn, in some member states suppliers may act for small consumers as a go-between to collect use-of-system charges due on behalf of the DSO and, eventually, the TSO.

Both TSO and DSO are network operators whose business operations, in particular their revenues and/or specific tariffs, are regulated by the national regulatory agency of a member state. The DSO being a regulated organization, regulatory arrangements determine how the DSO is affected in his financial position when underlying factors driving DSO revenues and expenditures change. The focal phenomenon of the DG-GRID project driving DSO costs and revenues is the rise of distributed generation. DG is penetrating Europe’s electricity distribution networks in an increasingly significant way and is commanding a rising share in Europe’s total electricity generation. In summary, this development impinges on:

i) DSO revenues through connection charges.
ii) DSO revenues through use-of-system charges.
iii) Incremental expenditures for network expansion or network upgrades.
iv) Incremental expenditures, which are operational in nature (e.g. energy losses, payments to DG operators for generation curtailments, other O&M costs).

Besides, prospective new revenue streams might be derived from increasing penetration of distributed generation, i.e. potential DSO revenues from DG operators for delivery of extra reliability, system information and storage.
2.2 Why network regulation?

Network regulation serves two main goals. First, it is to ensure efficient network operations (static efficiency) embracing current knowledge and, second, it should induce efficient long-term use of the system. The latter is to be effectuated through latest-vintage efficiency-raising network upgrading and expansion and, last but not least, introduction of innovative efficiency-raising network management approaches (dynamic efficiency). These twin goals incorporate the idea of equal and non-discriminatory access to networks.

Yet these goals are deemed illusive in an unbridled free market environment due to specific technological and economic characteristics. First of all, electricity network companies, including notably distribution network companies, are considered to be natural monopolies. The market, in which electricity network companies are active, is characterized by considerable economies of scale; perfect and even a limited degree of imperfect competition as described in standard economics textbooks is not applicable to this market. When a distribution grid is already laid out in an area, it would never pay out for a competitor to invest in a parallel grid: both parties will incur losses in that case. Factors that drive this natural monopoly feature are the high capital intensity of the market for electricity distribution, the high degree of asset specificity (lines once in the ground are not recovered), the long payback period of investments, non-storability with fluctuating demand and the combination of necessity and direct connection to customers (Ajodhia, 2006).

Monopoly firms tend to show an inclination towards limiting output and, in doing so, raising the market price to appreciably higher levels that socially optimal. Socially optimal price levels would arise if the actual monopoly market was to be a perfectly competitive one. Since electricity is considered to be a crucial input in the economy, the efficiency losses for society resulting from the monopolistic behaviour of unbridled distribution grid companies constitute the key reason for the design and imposition of network regulation.

As more and more distributed generation (DG) units are being connected to European distribution grids, the question arises: does current regulatory arrangements induce DSO behaviour towards DG that is efficient from the perspective of society and if so to what extent? On the one hand, society puts a premium value on sustainable energy supply, which includes for a major part DG. On the other hand, stakeholders on the consuming end of the supply chain do, if to pay anything extra at all, not wish to pay more than necessary to realize this.

2.3 Prevailing regulatory frameworks

Basically, two main types of tariff regulation can be distinguished. The first main category concerns ‘traditional’ cost-of-service regulation (also known as cost-plus, or rate of return regulation (ROR)) is applied, prescribing a regulated rate of return. The second one is referred to as incentive regulation (in the Americas known as performance based regulation). Key characteristics of incentive regulation are that the regulator delegates certain pricing decisions to the firm and that the firm can reap profit increases from cost reductions (Vogelsang, 2002).

All regulatory approaches face (i) the problems regarding asymmetric information, such as (ii) the difficulty for the regulator to set the ‘right’ (optimal) rate of return, and (iii) the difficulty of determining a proper evaluation method for rate base assessments. Problems (ii) and (iii) result from (i).

Asymmetric information between the regulator and the regulated DSO is a key issue in the regulation of natural monopolies. This issue is generally described in a principal-agent framework where the regulator is the principal and the regulated DSO the agent. The principal assigns tasks to the agent but the information asymmetries limit the principal in enforcing its preferred policy. In network regulation the main problem is the asymmetric information about efficient costs.
The regulator’s perception of efficient costs determines his productivity norm and, consequently, the so-called X-factor to be imposed on the DSO concerned.

The second problem is the difficulty for the regulator in setting the ‘right’ (optimal) rate of return with which the rate base is multiplied to determine the capital expenditures of a DSO. Regulators want to regulate the actual rate of return for two reasons. Firstly, they will set an ‘efficient’ cost of capital that is based on market rates. Secondly, they seek to achieve consistency between the estimates for different companies. A problem for obtaining reliable market-based estimates of efficient cost of capital is that DSOs are seldom listed on the stock exchange.

The third problem is the difficulty to determine a proper method for assessing the rate base (RAB: regulated asset base). The literature distinguishes two main methods to assess rate bases: (i) building blocks and (ii) total expenditures (TOTEX) method. The building blocks method contains two separated components namely an allowance for OPEX (operating expenditures) and an allowance for CAPEX (capital expenditures). Applying the TOTEX approach implies that the two components are summed up and that just the total expenditure level is regulated, irrespective of its composition into CAPEX and OPEX. Each method has its own advantages and disadvantages.

In the case of building blocks the regulator has to assess which investments have to be taken in the rate base, because benchmarking of CAPEX separately is usual not considered to be possible. Therefore, the investment projections of firms are generally taken as the base case for further regulatory scrutiny. This may prompt the DSO to overstate his investment projections in an attempt to get raised his allowable CAPEX and consequently his allowable revenues. One possibility to prevent firms from overstating investment projections is by deploying technical experts to assess all proposed investments of each DSO as is done in the United Kingdom. Moreover, in the building blocks approach no trade-off is made between OPEX and CAPEX. This, in turn, may adversely incentivise the DSO to record OPEX as CAPEX.

In the case of TOTEX the regulator does not have to consider specific investment projections, but instead has to perform a benchmarking analysis to determine the allowable levels of TOTEX. This analysis is to yield efficiency scores for each DSO. The higher the estimated efficiency performance of a DSO, the lower the X-factor applied to him and, consequently, the higher his allowable revenues. A DSO that is assessed to incur overly high overall costs is penalized by a relatively high X-factor, compared to his peers.

There are also some minor problems connected with the TOTEX approach. Because investments of DSOs are spread out over several years, firms cannot be readily compared to each other. This necessitates the use of investment data over different years, which can bring about practical problems. Sometimes an ex post calculation based on realised data has to be performed, yet this data might sometimes not be available or has been produced under different accounting conventions. Furthermore, under the TOTEX regime firms have more discretion whether they invest or not. Therefore, without quality regulation there is the risk that firms do not invest sufficiently in capacity expansion, let alone in assurance of quality of service.

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5 This section is based on Ajodhia (2006).

6 This depends on the chosen form of incentive regulation, which is dealt with in the next paragraph. The description here is based on different firm-specific X-factors and therefore on frontier benchmarking. There is also the possibility to use average benchmarking, in which case one generic X-factor is applied to all firms. This does not alter the fundamentals of TOTEX. In case of TOTEX and average benchmarking holds: the higher the efficiency of a firm, the more he outperforms the average costs as determined by the X-factor and the higher his revenues (if the X-factor is common, allowable revenues are changed with the same percentage for each firm, but at the same time costs of more efficient firms are lower resulting in more profits for a more efficient firm).
In conclusion, the building blocks and TOTEX approaches have each their pros and cons, although the disadvantages of the TOTEX approach seem to be smaller. Finally, it depends on the preferences of the regulator as to whether the building blocks or the TOTEX method is used.

Traditional regulation
In the past, network-based services in energy markets were regulated on a cost-plus basis. Within this type of regulatory regime, the short-run focus of the regulator is on the determination of regulated tariffs in such a manner that the DSOs can cover their operating and capital expenses plus receiving a guaranteed return on investment. In more technical terms, this type of regulation looks as follows:

\[
TAR_i = OPEX_i + r \cdot RAB_i
\]  

Equation 1 states that total allowed revenue \((TAR)\) is equal to the total of current (allowed) operating expenditures (including O&M, depreciation costs etc.) plus the regulated rate of return \((r)\) times the regulated asset base \((RAB)\). Any new investments undertaken by the DSO will appear in the regulated asset base. The regulated asset base is a measure of the value, approved by the regulator, of the company’s investment. Note that, to the extent that all investments are approved and the regulated rate of return is not set too low, no investment risk is borne by the DSO.

Provided the regulated rate of return is supra-competitive (e.g. as a result of the asymmetric information situation facing the regulator), the ROR mechanism incentivizes unregulated monopolistic utilities to structurally over-invest in network capacity. This led to the introduction of incentive regulation. Currently, traditional regulation is in place only in a few EU member states. Most member states have adopted some kind of incentive regulation.

Incentive regulation
Incentive regulation provides explicit incentives by fixing the length of the regulatory period ex-ante. In fact, for the duration of the regulatory period it decouples the direct link between costs incurred and revenues received by the DSO. The decrease of the frequency of regulatory reviews (typically to once every three to five years) enables the DSO to cash in on efficiency savings obtained in a regulatory period, i.e. a period spanning two subsequent ‘rate cases’. After such a period, a revision of costs and investments takes place and a new revenue or price equation is established.

Broadly, one can distinguish two types of incentive regulation; revenue cap and price cap. Dependent on industry characteristics and national preferences cumulating in national laws, regulatory authorities make a choice between both forms of regulation. Both can either be based on frontier benchmarking (comparing the DSOs performance with his most efficient peers) or average benchmarking (comparing the DSOs performance with average performance among his peers). By making comparisons between firms, benchmarking is poised to reveal at least a part of the asymmetric information between regulator and DSO.

The crucial difference between yardstick competition (yardstick regulation) and benchmarking is that yardstick competition attaches direct financial consequences (a change of the X-factors) to the outcome of the benchmarking procedure. With only benchmarking this is not the case: the regulator has much more discretion to deny or adjust the outcome of the efficiency comparisons, which have been made.

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7 This section is based on Cunningham and De Joode (2006).
The basic equation applied under respectively price and revenue cap regulation is the following:

\[ P_t = P_{t-1} \left( 1 + CPI - X \right) \]  \hspace{1cm} (2) \\
\[ TAR_t = TAR_{t-1} \left( 1 + CPI - X \right) \]  \hspace{1cm} (3)

The price cap equation (2) states that distribution tariffs \( P \) are allowed to increase with the rate of inflation (consumer price index, CPI) minus the X-factor, which represents the required rate of efficiency improvements as defined by the regulator. The revenue cap equation (3) is quite similar since it allows an increase in total allowed revenue by the same factor as in price cap regulation \( (CPI-X) \). Under revenue cap regulation, DSO tariffs need to be set at such a level that the level of total revenues does not exceed the cap.

However, there is an essential difference between price cap and revenue cap. In a pure revenue cap regime both the quantity of electricity sold and tariff can be determined, while under price cap regulation the price or tariff (basket) is fixed. Hence, under revenue cap regulation the firms may exert market power by lowering the quantity and thereby raise price. In contrast, lowering the sales volume is not profitable in case of price cap regulation because it means lower revenues. On the other hand, a revenue cap approach is more readily consistent with the promotion of energy efficiency than is the case with a price cap approach.

Under current practices, regulators applying a revenue cap approach to network operators tend to set limitations to revenue caps that render monopolistic behaviour much harder to exercise. For example, in the Netherlands besides the allowed revenues of the TSO also the TSOs tariffs are determined by the regulator. So, the consequences of using a revenue cap in regulation depend highly on the details of the regime.

Apart from that, revenue caps are often less restrictive than it would seem \textit{a priori}. Under a revenue cap system yearly \textit{ex post} adjustments might be made depending on the development of certain market indicators. The reason for this is the inability of the DSO to influence these developments. The possible \textit{volume adjustment factors} include the total number of customers and the total load connected to the network.

The length of the regulatory period that indicates how frequent X-factors are re-assessed is an important regulatory parameter. An increase in the length of the regulatory period may well incentivise DSO more to improve efficiency since expected rewards upon such improvements will be higher. In that case the DSO will receive more rents. In setting the parameter value the regulator faces a trade-off between more efficiency incentivisation (a longer regulatory period) and rent extraction (a shorter one). On the one hand, DSOs need to be sufficiently incentivised to improve efficiency; on the other hand, end-consumers need to profit from efficiency improvements as early as possible.

Company-specific components might be introduced in the basic price cap or revenue cap equation regarding:
- Quality-of-service performance, i.e. the Q-factor
- DSO-specific circumstances beyond the control of the DSO, e.g. network density, connection density and water crossings, subsumed by the Z-factor

Total allowable revenues could for instance be determined as follows:

\[ TAR_t = TAR_{t-1} \left( 1 + CPI - X \pm Q \right) \pm Z \]  \hspace{1cm} (3a)
2.4 DSO regulation in practice

After the theoretical considerations above, we now briefly describe regulatory arrangements as in place in eight EU member states: Austria, Denmark, Finland, France, Germany, the Netherlands, Spain and United Kingdom. Table 2.1 provides a brief overview of distribution network regulatory elements in these countries.

Of the EU member states considered, only Austria and Denmark currently apply an X-factor for an industry wide required efficiency improvement and X-factors for required efficiency improvement of individual DSOs. The Netherlands recently abandoned this approach and moved towards a common X-factor following observations that within-industry efficiency differences had been sufficiently reduced. It is noted, however, that the regulator in Germany and Spain respectively each plans to move to the inclusion of individual X-factor components. In the other countries a generic X-factor is used.

Regarding the correction for inflation, the majority of sampled countries use a standard consumer price index, but United Kingdom, Finland and Austria use different indices. Austria uses a weighted average of three different indices (wage index, building price index, consumer price index) whereas Finland only uses a building price index.

The length of the regulatory periods varies from three to five years. In some countries, the prevailing energy law allows the regulators to change the length between three and five years, dependent on the degree in which historical inefficiencies are (sufficiently) reduced. The reasons for choosing a particular period have already been presented in the previous section.

With only one exception, in all countries specifically considered by the DG-GRID project the regulator puts, at least part of, the responsibility for losses in the distribution system with the DSO. Spain has defined certain distribution loss standards, which are used to reward or penalize over- or underperformers. Hence, there is an incentive for Spanish DSOs to reduce distribution losses but in general the losses are fully passed-through to the end-consumers. In all other countries, the distribution losses are part of controllable operational expenditures and thus fully taken into account when determining X-factors. The price at which energy losses are valued for rate setting purposes varies: some regulators regulate this price (e.g., Austria), while other regulators require DSOs to compensate these losses by market purchases (e.g., the Netherlands).

Volume adjustment factors are applied in most of the countries considered. In Austria for example, the difference in estimated and realized volumes delivered is calculated each year within the regulatory period. Of the total difference obtained, 50% is compensated for in the price cap in the next year. Spanish DSO is compensated for volume changes to the tune of about 30%. In the UK in the determination of the efficient revenue of DSOs volume growth is also being taken into account (Pollitt, 2005).

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8 This represents a scale factor in Austrian and Spanish regulation of respectively 0.5 and 0.3.
Table 2.1  Overview of characteristics of distribution network regulation in selected EU Member States

<table>
<thead>
<tr>
<th>Common or individual X-factors</th>
<th>Austria</th>
<th>Denmark</th>
<th>Finland</th>
<th>France</th>
<th>Germany</th>
<th>Netherlands</th>
<th>Spain</th>
<th>United Kingdom</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of regulation</td>
<td>Incentive: price cap</td>
<td>Incentive: price/revenue cap</td>
<td>Rate of return regulation</td>
<td>Rate of return regulation</td>
<td>Incentive: revenue cap</td>
<td>Incentive: price cap with yardstick competition</td>
<td>Incentive: revenue cap</td>
<td>Incentive: price cap</td>
</tr>
<tr>
<td>Length of regulatory period</td>
<td>4 yrs</td>
<td>4 yrs</td>
<td>3 yrs</td>
<td>2 yrs</td>
<td>4 yrs</td>
<td>3 yrs</td>
<td>4 yrs</td>
<td>5 yrs</td>
</tr>
<tr>
<td>Inflation correction</td>
<td>Wage index (40%), building price index (30%) and consumer price index (30%)</td>
<td>Labour cost index (50%) and producer price index (50%)</td>
<td>Building price index</td>
<td>None</td>
<td>Consumer price index</td>
<td>Consumer price index</td>
<td>Consumer price index</td>
<td>Retail price index</td>
</tr>
<tr>
<td>Cost-basis</td>
<td>Totex</td>
<td>Building blocks</td>
<td>Building blocks</td>
<td>Building blocks</td>
<td>Totex</td>
<td>Totex</td>
<td>Unknown</td>
<td>Building blocks</td>
</tr>
<tr>
<td>RAB drivers</td>
<td>kWh and kW</td>
<td>kWh and kW</td>
<td>kWh</td>
<td>kWh and possible additional factors</td>
<td>kWh and kW</td>
<td>kWh</td>
<td>kW</td>
<td></td>
</tr>
<tr>
<td>Distribution loss responsibility</td>
<td>DSO</td>
<td>DSO (adjustment for large spot price changes)</td>
<td>DSO</td>
<td>DSO</td>
<td>DSO</td>
<td>Passed-through to end-consumer</td>
<td>DSO</td>
<td></td>
</tr>
<tr>
<td>Volume adjustment factor</td>
<td>Yes</td>
<td>Yes</td>
<td>Not applicable</td>
<td>?</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Source: DG GRID partner institutes

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9 Temporarily, incentive regulation is a price cap based on 2004 revenues in combination with rate of return regulation. RAB and annually adjusted capital cost factors are used for the RoR regulation. Benchmarking is carried out from 2007 and price caps will be adjusted in 2008 with individual X-factors.

10 The French regulatory office for energy (CRE) is making preparations for the implementation of incentive regulation.

11 As from 2009 incentive regulation will come into force, now cost-plus regulation is used. Therefore, some regulation characteristics are future but not current practice.
2.5 Do current regulatory frameworks encourage DSOs towards socially optimal management practices?

Following the trend towards liberalization of the European electricity market, the EU member state regulators tend to move from traditional cost-of-service regulation towards incentive regulation. This trend is prompted by the objective to foster more cost-effectiveness in the electricity network business for the good of the, notably retail, electricity consumers. Lately, quality-of-service gets more emphasis in DSO regulation with so far two selected member states having this integrated into their respective incentive regulation. European regulators are still pondering whether, and if so how, to integrate the evolution of fast rising levels of DG in distribution networks into DSO tariffs and revenues regulation.

As noticed above, current regulation to which DSOs are subjected exhibits a great variation among the EU member states. A more or less common characteristic is that prevailing regulatory frameworks typically do not allow at all or very little for the incremental cost of facilitating additional DG in a DSOs network and for (potential) benefits that integration of DG in operational procedures for the management of distribution networks might have. As a result, DSOs may perceive the facilitation of access of additional DG plants to their grid as something that makes their operations more complex and that is a financial bleeder, adversely impacting on their overall financial performance. Therefore, under current regulation prevailing in the EU member states one cannot take for granted that DSOs will fully co-operate with official DG stimulation policies and that they will readily provide level-playing-field access to potential new DG entrants.

Moreover, current regulatory frameworks of EU member states do present the DSOs little leeway to prepare themselves for a shift in operational management practices from passive network management (PNM) to active network management (ANM). Apart from the United Kingdom, no explicit innovation incentives are in place. The UK has implemented an Innovation Funding Incentive (IFI) and Registered Power Zones (RPZ). Under the former, DSOs are allowed to spend up to 0.5% of its combined distribution network revenue on research and development related to distribution network management. The latter is a scheme specifically aimed at technical innovation for connections of distributed generation. This is associated with a capacity-related incentive of 3 GBP per connected kW in the first five years of operation.

Except for the UK and the Netherlands, quality regulation in all selected EU member states is applied outside the scope of incentive regulation and notably through specific targets. The Netherlands and United Kingdom have included a Q-factor, representing quality improvements, alongside the X-factor in the regulatory equation. It remains to be seen as to whether explicit quality targets such as maximum number of disruptions or average interruption duration are sufficiently providing innovation incentives.

In principle, regulation puts an obligation upon DSOs to connect any applying party to the existing grid, who meets the prevailing grid code. However, the incremental costs of connecting customers with generation facilities are typically higher for DG units than ‘simple’ consuming units. This holds the more so where DG operators use intermittent generation technologies and are unpredictably changing from net consumer into net producer and vice versa (customers with DG facilities ‘behind the meter’). Moreover, after some network-specific threshold value and certainly under the prevailing fit-and-forget operational philosophy, the DSOs operating costs tend to increase disproportionately as a result of rising distributed generation. As stated already, existing network regulatory schemes do not duly allow for this. As a result, under regulatory frameworks prevailing in EU member states, DSOs may not be particularly eager to readily facilitate network access to (potential) distributed generators.
So far only the UK has introduced some specific schemes that make explicit allowance for the DSO performance regarding the provision of access by DG to their networks and related innovative demonstration projects. Some other member states, e.g. Germany, are contemplating regulatory changes in this direction.
3. On the future relationships between the DSO and his business partners

3.1 Introduction

This chapter seeks to explain how the contractual relationships between the DSO and his business partners may develop in the medium term under alternative passive and active operational management approaches. Also the effects of smart metering, unbundling of system support services and making use-of-system charges that are time and location dependent are considered. The contractual interfaces will be described between DSO, TSO, DG operator, suppliers, and end users under two different sets of policy scenario assumptions.

As already noted in the previous chapter, the regulatory context is of key importance to the choice of business model by the DSO. Therefore, prospective DSO business models have to be linked to alternative regulatory policy scenarios. Two prospective DSO business models are outlined: one pertaining to the baseline policy scenario consistent with passive network management (PNM) and the other to a policy scenario fostering active network management (ANM).

3.2 Baseline and alternative policy scenarios: common components

For both medium term policy scenarios up to year 2020 a number of common assumptions have been made about competition policy, the support for DG from society, and smart metering respectively. Common policy scenario assumptions are explained hereafter.

1. Competition policy

Overall competitiveness of the European economy is being promoted through liberalisation of the EU electricity and gas markets as well as by separation of energy production, transportation and distribution activities. The electricity transmission and distribution networks will be fully unbundled (through ownership unbundling) from commercial activities of the electricity industry including electricity generation, trade, and retail supply. Operating transmission and distribution networks will be regulated as now is the case. In this context, it is noteworthy that more competitive electricity and gas markets will provide independent DG operators more opportunities to enter these markets and, consequently, to implement economically viable business models. For example, third party aggregators may offer DG value enhancing services for e.g. accessing power exchanges or forward power markets, or the provision of balancing and ancillary services. This does not only apply to the active network management scenario but also to the passive network management scenario.

12 The unbundling issue will not be further addressed in this report. Skytte and Ropenus (2005b) already made the point that effective unbundling is essential for achieving a level-playing-field treatment between the various (potential) DG operators, as incumbent integrated suppliers with distribution network assets may foreclose potential new players, including lone DG operators, to enter the market. The latest electricity sector enquiry (EC, 2007a) under auspices of DG Competition suggests that still a lot of implementation measures have to be taken in several member states to comply with the legal unbundling requirement of the Electricity Market Directive (EC, 2003a). Moreover the aforementioned enquiry raises the question as to whether ownership unbundling is needed to achieve a genuine level-playing-field situation. In the ensuing we will assume that effective unbundling will be achieved EU-wide in the short term, recalling that absence of effective unbundling will seriously weaken the effectiveness of further regulatory arrangements to improve the performance of network operators, especially regarding the facilitation of efficient network integration of fast increasing levels of DG.
2. An enduring, strong societal support for DG
The strong societal pressure to enhance the role of DG in the generating mix is assumed to endure. Three major policy drivers will keep the pressure on: (i) the climate change issue, (ii) the long-term energy supply issue, (iii) industrialisation policy in MS with strong representation of DG stakeholders. As a result, on average market support mechanisms remain slowly subsiding but quite significant value driver to distributed generators, i.e. especially renewables-based and less so conventional CHP operators inter-connected to distribution networks.

3. Implementation of smart metering
Smart metering at the customer’s end of the DSOs network does at the very least provide information on power ejections from and injections into the grid at the at the customer’s end for short time intervals soon after each interval has lapsed. This enables DSOs, and where applicable electricity suppliers to obtain automatic meter readings for billing purposes and consumers to be informed about their consumption over short time intervals. In more sophisticated implementation modes that may assume significance in the medium term, smart metering may also enable automatic demand response options (domotica options and third-party remote control options for generation of ancillary system services based on bi-directional communication between a central actor and an intelligent devise interconnected with the smart meter at the consumer end) and, notably, (other forms of) active network management based on two-way communication flows between the DSO and intelligent devises attached to the meters at the customer’s end involving the capital assets of distributed generators as well.

Smart metering at the network user’s point of common coupling with the network fits entirely into both the passive and active network management scenario for making DSOs able to deal with the fluctuations in energy supply of DG by making customers more sensitive to changes in energy prices. For the business model analysis it is relevant how the institutional arrangement of smart metering will be organised. For DG operators and large consumers it is assumed that they themselves have to arrange for metering equipment and for certified meter reading companies that will have to provide the DSO with meter readings.

Given the competition-sensitive information metering services can provide to electricity suppliers, the economic perspective suggests that suppliers should not be entrusted with retail metering. It could be entrusted either to the - fully unbundled - DSO or to an external certified metering company. In the ensuing, it will be assumed that the DSO will be in charge of retail metering.13 Moreover, in order to not unduly annoy retail customers with separate home visits and an overkill of electricity-supply-related bills it will be assumed that the supplier will be charged with collecting metering surcharges on the electricity bill of retail customers.

3.3 Different policy components
The two policy scenarios in this report relate to the prevalence/absence of an emerging and enduring strong societal pressure to genuinely integrate DG into the operational management of regulated electricity networks in a cost-efficient way. Integration would be incentivised by governments through network regulating agencies and DG support agencies using appropriate, wide-ranging packages of incentives and penalties. This condition is considered essential for overcoming the strong institutional inertia inhibiting genuine integration of DG in power network operations.

13 It is noted that under current conditions with less effective unbundling in most European countries, that a certified metering company without any ownership ties with electricity suppliers might be a better alternative option. It is assumed that on longer term unbundling will have been implemented effectively throughout Europe.
3.3.1 Description of baseline scenario

The baseline policy scenario presumes that all joint scenario assumptions that have been explained above, will be met but that no appropriate fine tuning of DSO and DG market support regulation will be implemented, necessary for bringing about genuine integration of DG in network management practices. The baseline scenario implies that current ‘fit and forget’ practices prevailing in operational network management all over Europe, will endure. Under this operational philosophy the integrity and reliability of network services rely primarily on a very robust way of planning network expansion and network reinforcement that can successfully face any plausible future demand for network services without pro-active reliance on network services from distributed energy resources.

In the baseline scenario distributed generation will penetrate fast but even so the prevailing passive network operational philosophy will not be changed. Network operators will meet increasing operational challenges because of penetration of DG. They will tend to address these challenges primarily by robust conventional network reinforcement meeting at least the (N-1) contingency rule, but also gradual replacement in MV and LV distribution networks of obsolete components by controllable components such as on-line tap changing transformers and installing more network monitoring sensors. Moreover, DSOs will keep on lobbying for more stringent grid codes and will, when possible, at times tacitly obstruct grid access of distributed generators by erecting ‘red tape’ barriers.

3.3.2 Description of alternative policy scenario

In the alternative policy scenario network regulatory agencies and DG support agencies will implement dedicated government policies to foster integration of DG in network operational management. Government policies will stipulate fast implementation of smart metering programmes targeted at all network users including retail customers. This will enable not only trading operations (accounting records of e.g. power quantities at quarterly, half or full hour time intervals) but also near real-time remote control by network operators and commercial third parties. In the alternative policy scenario the (genuinely) unbundled DSO will provide access for both DSO and (at a regulated fair charge) third parties to the meter interface at the customer’s doorstep on a level-playing-field basis subject to protocols ensuring explicit customer consent and absence of privacy infringements. Network regulators will strongly stimulate through appropriate incentives and penalties introduction of smart network tariffs such as time- and location-differentiated use of system charging. This will proceed in an indirect way through smart output-based incentives promoting efficient DG integration. Also formal DSO investment planning procedures will be mandated to explicitly include DG flexibility into peak demand and system reliability risk assessment guidelines.

Moreover, DG support mechanisms will not only minimise abnormal profits by DG plant owners. DG support mechanisms will also be designed smart to foster the disposition of DG to enhance the social value per unit of generation (avoided consumption) including the provision of ancillary services that enhance social value. For example, in the case of production subsidies (feed-in tariffs; feed-in premiums) such technology specific subsidies per MWh will be time-differentiated. This could for example be aligned to movements of the commodity price on the

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14 For example, the regulator may set, for the upcoming regulatory period, network-specific annual standards for average load (in MW) to be facilitated by a DSO. Ex post the regulator may reward (penalise) the DSO for negative (positive) hourly peak load deviations from the load standard for each hour of the year. This way the DSO is encouraged to apply time-differentiated UoS charges to network customers that may bring about a flatter load duration curve. This in turn will reduce power losses in the DSO network (high loads having a disproportionately negative impact on line losses on the order of the power two) and postpone the need for investment in expanding the load-carrying capacity of distribution lines.
power exchange, as could be the number of guarantees of origin (GOs) issued per eligible MWh generated in countries with a Renewable Portfolio Standard as main support mechanism.\textsuperscript{15}

On the one hand, smart network tariffs in tandem with smart DG market support policies as well as DG-integrative network management practices will strongly induce DG operators to liaise with commercial providers of specialist operational services including notably DG aggregation services. On the other hand, pushed by the regulator and by more responsive and reliable DG behaviour, network operators will gain more confidence in relying on active network management philosophy using ICT infrastructure.

3.4 DSO business models

The diagrammatic representations of the business models (Figures 3.1 and 3.2) show:

- **Solid arrows**: financial flows between the DSO and third parties. Black-arrow labels summarise the nature of the product/service provided in reverse direction. With the exception of remuneration of production factors under direct management of the DSO (salaries of own staff and return on capital invested), the diagrammatic representations of the financial flows visualise his major revenue in-flows and expenditure out-flows.

- **Intermittent arrows**: data communication flows between the DSO concerned and external parties for remote-control network operations. This gives additional visualisation of aspects of a DSO business model related to passive and active network management.

Note that no market-oriented data flows will be shown, so as to keep the complexity of the representations within reasonable proportions.\textsuperscript{16} For the same reason, financial and network information flows between other actors in the business model diagrams are not shown. Moreover, in order to not render the diagrams overly complex, internal financial flows such as salary payments are not shown either. The resulting two diagrams, Figures 3.1 and 3.2, highlight some key differences between the ANM and PNM business models of a DSO.

3.4.1 Passive network management business model

The baseline DSO business model assumes continuation of a passive network management philosophy. In the baseline policy scenario the DSO is less able to address mounting network constraints as a result of high penetration of distributed generation in their networks, unless they undertake massive grid reinforcement programmes. The baseline scenario may imply higher Use of System (UoS) tariffs and hence a less economic viable environment for DG operators. These likely implications and the slower implementation of smart metering and monitoring systems in the baseline policy scenario as compared to the scenario with active network management may attenuate the fast penetration of DG. Hence, although there will be appreciably more penetration of distributed generators than at present, DG penetration will be less in the baseline scenario than in the ANM policy scenario. The diagrammatic presentation of the baseline DSO business model is shown in Figure 3.1.

\textsuperscript{15} Along with a mechanism to re-align the total number of GO issued per period (e.g. month) to the total number of MWh generated. Note that in both policy scenarios national GO tracking systems are assumed to be fully integrated with national support mechanisms.

\textsuperscript{16} Another reason is that data communication flows for remote control of DG will in certain cases be more dense and requiring higher resolution than market-oriented data flows. Note that programme time units of wholesale and balancing markets are usually standard time intervals of 15, 30, or 60 minutes, whereas network management warrants (almost) real-time information. Evidently, in the scenario with ANM it is the latter type of information, that ‘smart metering’ and monitoring systems should be capable to record and deliver to remote control centres.
The business model encompasses the following major components:

**Revenues**
- The DSO imposes regulator-approved connection charges (C) and use-of-system (UoS) charges to distributed generators (DG). By definition, the connection charges for distribution generators are shallow (see Section 2.1).
- The DSO imposes regulated connection, (cascaded) Use of System charges to end consumers connected to the distribution network.
- Through intermediation of suppliers of retail consumers in the DSO area, the DSO receives regulated metering charges for the allowable cost to recover the up-front procurement cost of the meter at the retail consumer’s doorstep and the allowable recurrent metering costs.\(^{17}\)

**Expenditures on outsourced goods and services**
- The DSO passes on payments for approved transmission-system ancillary services (TAS) charges and use of transmission-system (UoTS) charges from consumers to TSO.
- The DSO contracts large generators to deliver the energy needed to cover losses in the distribution system, either directly or indirectly through brokered trades or power markets.
- The DSO incurs expenditures for non-power material inputs including payments to network equipment vendors, outsourced maintenance and ICT providers, spare parts and consumables.

**Network data flows between DSO and third parties for remote-control capabilities**
In accordance with grid code requirements, the DSO has network-related data exchanges with TSO, distributed generators and large distributed electricity customers. Suppliers (of profiled, small customers) are assumed to have no generation facilities within the purview of the DSO.

\(^{17}\) This is consistent with the scenario assumption that the (unbundled) DSO will be nominated to assume the role of regulated metering company in the DSO franchise area, both the baseline and the alternative policy scenario. Note that it is assumed that the certified meter reading market for large consumers and distributed generators is free. Small distributed generators at household level ‘behind the meter’, exporting to the grid might be considered as small consumers with negative demand in this respect.
They do not physically cater the profiled customers, but are rather the administrative interface between their customers and the DSO.

3.4.2 Active network management business model

The active network management business model is depicted in Figure 3.2 below. It contains the same type of revenue and expenditure flows as the corresponding baseline model. Yet in the ANM policy scenario, as a result of active network management conducted by the DSO, a range of new financial flows appear. Also the role of conventional flows may change in significance as explained below. Changes compared to the baseline business model are highlighted in blue fonts.

Figure 3.2 DSO: Future business model with active network management

Revenues

- The DSO imposes regulated connection and use-of-system charges to distributed generators. These will also be charged to suppliers owning DG assets in the purview of the DSO. Connection charges for distributed generators will be shallow with at least partial socialization of concomitant reinforcement costs in UoS, UoS will be ‘smartened’: time-variable UoS charges with locational signals will be introduced, which will greatly improve cost-reflectivity of distribution network services rendered to distributed generators. As DG aggregators will command a significant role, so will be the financial flows between DG aggregators and the DSO.
- The DSO imposes connection, (cascaded) Use of System charges and metering charges to end-consumers connected to the distribution network. Due to complexity of operational management, charges for DSO arranged ancillary services will be appreciably higher. Conversely, charges for TSO arranged services might well be lower than in the baseline as localised ancillary services as compared to system-wide ancillary services may gain in significance.
- Through intermediation of suppliers of retail consumers in the DSO area, the DSO receives metering charges for the allowable cost to recover the up-front procurement cost of the meter at the retail consumer’s doorstep and the allowable recurrent metering costs. Allowable DSO revenues for metering services rendered will be higher than in the baseline due to apprecia-
bly higher demand for metering services by suppliers on behalf of their customers which contractually consented to delivery of load flexibility services.

**Expenditures on outsourced goods and services**

- The DSO passes on payments for TSO-arranged ancillary services charges and use of transmission-system charges from consumers to TSO. In the ANM policy scenario the importance of transmission-network facilitated generation and TSO-arranged ancillary services will be appreciably less compared to the baseline, and so will the related financial flows from DSO to TSO.

- The DSO contracts both DG and large generators to deliver the energy needed to cover losses in the distribution system. For large generators this will proceed either through direct bilateral contracts or indirectly through brokered trades and/or power markets. As the reports of Cao et al. (2007) and Joode et al. (2007) indicate, the impact of active network management on DN energy losses is somewhat ambiguous. Energy losses will reduce if DG starts to contribute to the network. However, if DG increases energy losses will increase too, because of the larger load flows over the network. Smart regulation can help to reduce energy losses under active network management. In this policy scenario it is assumed that local DG will contribute to make up for local line losses. Hence, it can be safely assumed that, compared to the baseline, the need for the DSO to call upon large generators to compensate for energy losses will be less and so will be the associated financial flow.

- The DSO incurs expenditures for non-power material inputs including payments to network equipment vendors, outsourced maintenance and ICT providers, spare parts and consumables. The composition of the financial flows concerned will be quite different from the baseline, while at this stage it cannot be assessed how the total amount concerned will compare in the active network management policy scenario to the baseline. Investment in network reinforcement (including upgrading of switch gear and transformers and ICT infrastructure) in network sections where DG feeds in is poised to rise. On the other hand, investment in network expansion of higher voltage DN sections can be postponed.

Active network management will imply new expenditure flows:

- DSO-arranged ancillary services (DAS) provided by DG (including compensation for DN energy losses), flexible loads (large consumers and willing retail consumers remotely controlled by their suppliers). Figure 3.2 shows that, in principle, DG aggregators may play their part in arranging the provision of certain DAS and as intermediary in the financial settlement of DAS on behalf of their DG clients. The associated financial costs have to be recovered by the DSO through allowable network tariffs as explained above.

### 3.5 Conclusion

To create a favourable business environment to bring about a paradigm shift in DSO operational management from PNM to ANM, concurrent, fine-tuned, smart public interventions are warranted on a broad front of the policy framework regarding electricity network regulation and DG market stimulation. Such interventions include:

- Smart stimulation of DG, especially renewables based DG that allows for the time-variable social value of DG produce as for instance indicated by the baseload price.
- Proper introduction of smart metering of adequately high resolution.
- Fostering of time- and location dependent use-of-system charging by DSOs, for instance by making DSOs accountable for distribution system power losses in a time-variable way with higher (lower) rewards for lower than (distribution network dependent) standard losses at times of high local energy demand and vice versa for higher than standard losses.
- Facilitate the recovery of justifiable IT-related cost warranted by ANM (see also Chapter 5).
4. On the roles for DG and DSOs in ancillary services provision

4.1 Introduction

This chapter makes a preliminary assessment as to whether ancillary services can generate additional value for DSOs by involving DG. The chapter structure is as follows. Section 4.2 gives a short introduction to the various ancillary services. Section 4.3 presents an assessment of costs and benefits for DG of providing ancillary services. In case DG is able to deliver ancillary services more cheaply to the DSO than the TSO, DG has additional value for the DSO. Finally, alternative commercial arrangements for ancillary services provided by DG are identified in Section 4.4.

4.2 A taxonomy of ancillary services

The term ancillary services can be defined as follows: ‘Ancillary services are those services provided by generation, transmission and control equipment which are necessary to support the transmission of electric power from producer to purchaser. These services are required to ensure that the System Operator meets its responsibilities in relation to the safe, secure and reliable operation of the interconnected power system. The services include both mandatory services and services subject to competition’ (Eurelectric, 2000).18 Dependent on their nature, some ancillary services might be provided locally at the place where they are requested, but other ones are not location-dependent and are typically provided all over the power system control area. Examples of the former are reactive power supply and black start capabilities, while an example of the latter is frequency response.

Ancillary services can be classified *inter alia* on the basis of two fundamental characteristics of alternating current (AC) power delivered to a customer, namely frequency and voltage. The frequency characterizes the number of times that the voltage cycles from maximum to minimum voltage and back again. Frequency affects the operation of electrical motors, many of which draw more power and run faster at higher frequencies. The greatest value of a stable frequency is provided to large generators, which suffer less stress when run at constant velocity. Voltage on the other hand can be interpreted as electrical pressure, causing electrical currents moving from one point to another. Generally electrical appliances are designed to operate for a specific voltage and associated electrical current. In case of the application of larger voltages electrical appliances may suffer severe damage or stress. Lack of voltage reduces the power delivered to appliances and may lead to inadequate operation.19

Usually frequency is subdivided into frequency response, spinning and standing reserve and load following. These notions are defined as follows:

1. **Frequency response** (a synonym for primary frequency control): ‘The objective of primary control is to maintain a balance between generation and consumption within a certain synchronous area, using turbine speed or turbine governors. By the joint action of all interconnected undertakings, primary control aims at the operational reliability of the power system of the synchronous area and stabilises the system frequency at a stationary value after a disturbance or incident in the time-frame of seconds, but without restoring the reference values of system frequency and power exchanges... Adequate primary control depends on generation resources made available by generation companies to the TSOs...’ (UCTE, 2004). In case demand is

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18 Alternative definitions are given in (Eurelectric, 2004) and (ILEX, 2004).
19 This paragraph borrows from (Stoft, 2002).
greater than generation, the frequency falls while if generation is greater than demand, the fre-
quency rises.

2. **Spinning reserve** is a synonym for secondary frequency control. UCTE (2004) defines sec-
dondary frequency control in the following way: ‘Secondary control maintains a balance between
generation and consumption within each control area as well as the system frequency within the
synchronous area, taking into account the control program, without impairing the primary con-
trol that is operated in the synchronous area in parallel but by a margin of seconds. Secondary
control makes use of a centralised automatic generation control, modifying the active power set
points in the time-frame of seconds to typically 15 minutes. Secondary control is based on sec-
ondary control reserves that are under automatic control. Adequate secondary control depends
on generation resources made available by generation companies to the TSOs’.

3. **Standing reserve** is a synonym for tertiary frequency control. UCTE defines tertiary fre-
quency control as follows: 'Tertiary control uses tertiary reserve {15 minute reserve} that is
usually activated manually by the TSOs after activation of secondary control to free up the sec-
ondary reserves. Tertiary control is typically operated in the responsibility of the TSO'.

4. **Load following** can be described as the manual changes of active power in steps of 15 min-
utes. Through variation of generation the hourly and daily variations in system load can be met.

Besides frequency services, there are some other remaining important ancillary services, which
are summed up below. The most important of them relates to voltage.

5. **Voltage control** is carried out in order to maintain voltages within tolerances and thereby to
prevent damage to customer equipment. Voltage control reduces also the reactive power flow
and consequently distribution losses. However, in order to keep the voltage within tolerances it
is sometimes necessary to inject reactive power into the system (Raineri et al., 2006).

6. **Black start** is the process of restoring the power system after total or partial shutdown of elec-
trical supplies throughout a network.

7. **Islanded operation**: when the network has broken down into islands through a disturbance, it
is preferable if the resulting different parts of the grid can be operated independent of the (bro-
ken-down) mains system.

### 4.3 Assessment of costs and benefits for DG of providing ancillary services

This section explores whether there exist the possibility for DG to provide ancillary services
cheaper than is the case with conventional delivery modes. If this is the case the DSO may be
able to buy ancillary services cheaper from DG operators than procured by the TSO from con-
ventional generators. First, an overview is given of the technological capability of different
types of DG to provide ancillary services.

**Technological capabilities**

Table 4.1 shows the ancillary services mentioned in the previous section. In this case black start
and islanding are taken together as one item. Network support is defined as generator power
flow management in order to control distribution network voltages and therefore prevent dam-
age to customer equipment. So network support equals voltage control as defined in the previ-
ous section. The voltage variation widens through increasingly actively managed distribution
networks and hence wider ranges of power flows (including) reversals together with increased
penetrations of distributed generation. By applying generator based solutions network rein-
Enforcement costs may be avoided and connection costs for DG possibly can be reduced (Mutale and Strbac, 2005).

Table 4.1 Summary of technology capabilities of DG in UK

<table>
<thead>
<tr>
<th>Ancillary service</th>
<th>Non-renewable DG Technology</th>
<th>Renewable DG Technology</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CCGT</td>
<td>Large CHP</td>
</tr>
<tr>
<td>Size</td>
<td>&gt;100 MW</td>
<td>1-100 MW</td>
</tr>
<tr>
<td>Frequency</td>
<td>YES</td>
<td>Limited</td>
</tr>
<tr>
<td>Reserve</td>
<td>YES</td>
<td>Possible</td>
</tr>
<tr>
<td>Reactive</td>
<td>YES</td>
<td>YES</td>
</tr>
<tr>
<td>Network support</td>
<td>YES</td>
<td>YES</td>
</tr>
<tr>
<td>Black start</td>
<td>Possible</td>
<td>Future island opportunity?</td>
</tr>
</tbody>
</table>


The distinct distributed generation technologies are not explained in this report. See for more information about the different technologies Mutale and Strbac (2005). The uncertainty around future island opportunities is caused by the inability of current DG technologies to effectively provide islanding services. However, Mutale and Strbac (2005) see perspectives for new, energy production driven DG installations which are able to provide islanding services on LV networks of DSOs. Nowadays, however, both urban and rural networks provide little demand for islanding services from DG. Urban networks experience few faults as they are mainly underground networks, while interruptions of rural networks impact little customers so in both cases the overall value of interruptions seems to be too small to implement islanding operation. On the other hand the demand for higher quality of supply is expected to rise in the future. On the short to medium term, however, islanding services do not have to be provided by DG.

Economic valuation of provision of ancillary services by DG

The valuation of technological capabilities to provide ancillary services relates to the economic value of these services. When demand of customers for a particular service is small or supply is already generous, prices tend to be low. Even when technological capabilities of a certain DG technology to deliver a certain ancillary service are high, it will then not be provided by new market parties like DG. With regard to the UK situation, (ILEX, 2004) and (Mutale and Strbac, 2005) have surveyed potentially interesting ancillary services for provision by DG. According to both studies, the most feasible ancillary services in the short to medium term to provide by DG are TSO frequency response, TSO regulating and standing reserve, and DSO security of supply. Other TSO services including warming & hot standby, fast reserve, fast start and black

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20 The UK is taken as case study quite often for two reasons. First, the UK provides practical examples of the issues under investigation and, at the same time it is one of the most competitive markets in Europe (cf. Mutale and Strbac, 2005).

21 In the UK a distinction is made between payments for services made according to Holding (availability) and payments for Response Energy Payments (delivered energy). Holding Payments to generators are no longer based upon cost-reflective €/MW/h payments, but generators can submit commercial holding prices on a monthly basis (National Grid, 2005). Response Energy Payments, paid to and by generators, are remunerated on a €/MWh basis according to a monthly average of system buy and sell prices obtained from the Balancing Mechanism (BM) under NETA or rather the new BETTA scheme (Mutale and Strbac, 2005).
start, have lower value ‘due to low materiality, limited market potential and/or inapplicability to
distributed generation’ (Mutale and Strbac, 2005: p. 32). 22

The low materiality and, therefore, limited market potential of some services is strongly con-
connected with the requirement for generators to have ‘headroom’ in place in order to be able to in-
crease output and provide ancillary services. By implication, the generators providing such ser-
vices will, to a lesser or greater extent, be part-loaded. 23 Part-loaded operation enables rapid
changes in generator output. Yet it also implicates fewer revenues to generators from energy
supply due to lower capacity utilisation and (technology-specific) lower fuel efficiency. Moreover,
variable utilisation patterns may imply higher wear and tear. Therefore, it is necessary that
generators are fully remunerated for their opportunity costs of not being able to deliver energy
to the grid when providing ancillary services. The third reason as suggested above, inapplicabil-
ity to distributed generation of some services has to do more with technical reasons (see e.g. Ta-
ble 4.1 above).

In the ensuing a preliminary assessment will be made of the value of ancillary services, notably
but not exclusively the ones identified by (ILEX, 2004) and (Mutale and Strbac, 2005) as poten-
tially important for DG operators. Successively, TSO frequency response, TSO regulating and
standing reserve, DSO security of supply, voltage control and reactive power, and islanded op-
eration will be dealt with.

In the UK, the value of TSO frequency response varies between approximately € 0.59/kW per
annum for (DFIG) wind generation and approximately € 3.72/kW per annum for CCGT tech-
nology, excluding holding costs. If these amounts are related to total annual revenues (including
in the case of windpower revenues from the sale of Renewable Obligation certificates (ROCs,
i.e. certificates used to prove compliance with the UK’s renewable portfolio standard), the reve-
 nues of wind farms and CCGT units would increase only by less than 0.5 percent and at most 2
percent respectively on account of provision of TSO frequency response services (Mutale and
Strbac, 2005).

Again in the UK, the value of TSO regulating and standing reserve is around € 10.36/kW per
annum. At that value non-renewable generators provide standing reserve services to the TSO. In
principle, standing reserves can also be provided by distributed renewable generation, that is,
directly in principle for larger units and by way of aggregation of small renewable generators
into virtual power plants. Yet for distributed renewable generators it is not economic, due to the
necessity of part-load operation and the associated loss of renewable energy stimulation benefits
on top of commodity sales forgone.

Furthermore, the costs of entry for the lowest costs OCGT 24 plant are more than € 67/kW per
annum. Hence, for most DG units accessing the market for frequency services is not yet attrac-
tive. In the future, if revenues per kW per annum increase, aggregation services can support the
increase of DG participation (Mutale and Strbac, 2005). Also demand-side participation, such as
load shedding based on interruptible supply contracts, can contribute to the accomplishment of
frequency control (Raineri et al., 2006).

22 There are some important differences between the transmission and distribution network. First of all the transmis-
sion network is characterized by fewer differences in size and types of generators and by using synchronous elec-
trical generators. Secondly, the bigger differences in size of generators connected to the distribution network lead
to a wider range of connection voltages. Thirdly, ‘features such as remote start-up, automatic voltage regulation,
fault ride through, parallel running, governor control, islanded operation and real time metering have historically
not been features of distributed generation design although many of these are key to the provision of ancillary ser-
vices’ (ILEX 2004: p. 30).
24 OCGT stands for Open Cycle Gas Turbine.
DSO security of supply services are among the most feasible ancillary services to be provided by DG. Under certain circumstances an extension of the quantity of DG connected to the distribution network can be an alternative to network reinforcement. New network automation may obviate or defer conventional network investments in e.g. reinforcement. Based on the avoided costs of DSO network reinforcement, in the UK the potential social value of providing network security services by non-intermittent generators is estimated to be in the range of € 1.48/kW to € 17.8/kW per annum (Mutale and Strbac, 2005). These amounts are highly dependent of the complexity of the network concerned. Likely payments, if based on the DSOs avoided costs, will be mainly at the lower end of the mentioned range, with an average payment to the tune of roughly € 4.45/kW per annum. Mutale and Strbac (2005) also project the revenues of providing this ancillary service in relation to the total revenues of a DG. In the case of renewable generation an important part of the total revenues is the income from market support benefits, for example ROCs. In case of a biomass generator the ROC income sums up to € 5.94 m per annum and in case of a non-renewable generator expected revenues are € 8.83 m per annum. According to Mutale and Strbac, the share of revenues arising from providing security of supply in total revenues would be less than 1 per cent for renewable generators and less than 3% for the non-renewable generators.

Voltage control is another service that can be supplied by distribution generation. According to Mutale and Strbac (2005) the provision of this service by DG is limited to system restoration after a fault has occurred as: “... under normal operating conditions the network will provide services to DG in order to maximise DG output (e.g. tap changing and flow control)”. Furthermore, due to the strict voltage standards the possibilities for DG to provide voltage support are limited. The potential value of this service is estimated to be € 2.23/kW per annum. According to Raineri et al. (2006), the consumer price of voltage control in the Scandinavian countries is about US$ 2.7/MVArh, but supplier receive only an operational payment for quantities exceeding the mandatory range. Both ILEX and Mutale and Strbac remark that opportunities for DG will improve when the deployment of DG increases.

In addition to the use of reactive power in voltage control it is also possible to diminish the import of reactive power from the TSO through provision of reactive power by DG connected at lower voltage levels. The value of DG regarding this service is approximately € 1.78/kW per annum.

As concerns the overall service quality level, it is stressed that this service is linked to the islanded operation capability of DG. This capability enables DG to reduce the impact of outages and thereby to reduce the number and length of customer interruptions. The benefit of islanded operation is approximately € 2.08/kW/annum and € 28.23/kW/annum for residential and commercial customers respectively (Mutale and Strbac, 2005).

In general, “the analysis undertaken suggests that the value of the most feasible ancillary services will be relatively low. Consequently, such services will represent limited incremental revenue opportunities for DG. In general, it would not be possible to develop business cases for investing in DG solely on the basis of ancillary service income.” ((ILEX, 2004: p. 140); (Mutale and Strbac 2005: p. 5). Only, if DG is fully compensated for the opportunity costs of not being able to deliver energy to the grid but instead providing an ancillary service, the provision of ancillary services by DG will become significant. It should be noted, however, that the focus of both the ILEX and the Mutale and Strbac studies had a short to medium term perspective. In the long-term fundamental changes to the architecture of power systems are in the offing. As a result, the prospects for DG to provide ancillary services may improve substantially in the long run. Moreover, these findings for the UK are not necessarily valid for other member states. Other countries have other network topologies and other regulation schemes in place, which are in many cases less market-oriented.
4.4 Options for commercial arrangements for ancillary services by DG

Different arrangements between network operators and distributed generators for the provision of ancillary services by the latter are possible. To that effect, the characteristics of the ancillary service concerned is relevant, especially whether the service can be provided anywhere in the TSO control system or is needed in more restricted local areas.

Furthermore, due to the technical capabilities of generating equipment it might not be feasible for DG operators to provide several ancillary services concurrently. Also, for some services statutory technical limits exist which are difficult to comply with (for example voltage control). As a consequence, DG might have to select the most valuable feasible option for providing ancillary services.

Two main categories of delivery approaches can be discerned, i.e. market-based and non-market based approaches.

*Market based approaches*
Ancillary services can be characterized as to whether they can be sourced locally or globally (i.e. anywhere in the TSO control system), by the distinction between frequency and voltage and by the distinctive broad goals of system provision and system restoration. Consequently, rather than one ancillary services market a range of markets might develop: one for each type of ancillary service.

For the provision of ancillary services *laissez faire* is not a feasible option. Market interventions by system operators are needed. Ancillary services benefit the entire market and are either public goods or have large external effects. Moreover, supply and demand balancing as well as maintenance of quality-of-service standards warrant well-coordinated, (close to) real-time, interventions. For these reasons, TSOs and in synchronous areas even supra-national bodies such as UTCE as well, coordinate electricity supply system operations. Typically TSOs are responsible for the provision of ancillary services in their control area. Regarding localized ancillary services they do so in close collaboration with DSOs to which they may delegate major responsibilities in this regard. All ancillary services markets have a fully regulated demand side. As the TSO or the DSO is the only party asking for ancillary services from DG in the TSO control or DSO service area, each market for ancillary services is a monopsony. Depending on market characteristics the supply side of some markets may have a mandatory or regulated character or can be deregulated (Stoft, 2002). In the latter case, the competent network operator designs and implements *tendering based procedures*, equates the requirements for eligible bidders and requests potential providers including DG to submit bids.

In order to make such tendering procedures operational and to make markets accessible and transparent for market players including DG operators, regulatory rules considering contracts for ancillary services have to be as clearly, standardised and simple as possible. Otherwise, different contract structures will develop which result in additional transaction costs, both for DG and for the industry as a whole, whilst competition from DG to existing conventional generation in providing services would diminish. Hence, standardization of contracts when applying tendering for ancillary services is warranted.

Furthermore, both from private and social perspectives the balance between market turnover and transaction costs is of importance. Market turnover is determined by the reward DG is given by the DSO for supplying ancillary services. Preliminary indications presented in the previous section suggest that, to date, the provision of these services delivers only marginal revenues, that is, only a tiny fraction of the total DG revenues. As a result, the costs for setting-up new markets for some services are probably higher than the revenues with negative implications for the value of new markets for firms as well as society. In general this may be the case if the services needed are highly localized, which would result in a myriad of sub-regional markets.
Hence, for highly localized ancillary services such as local reactive power provision market-based approaches might be less appropriate. Market depth (liquidity) of the resulting markets would be very small, price volatility large, and risks of market power abuse might be serious in the case of market-based approaches for localized ancillary services. Conversely, for ‘global’ ancillary services, such as the provision of regulating and reserve power, market-based approaches would qualify for serious consideration and have in fact already been implemented in several member states.

**Non-market based approaches**

Market-based approaches may not be possible on account of too high costs in relation to benefits, the local nature of some services and/or because of a shortage of market players. Non-market-based approaches could be a solution in those cases. One option would be *negotiated bilateral arrangements* between DSO and DG. However, the distributed generator has little information compared to the DSO. Hence serious information asymmetry may prevail between both parties. In order to prevent the DSO from capitalizing on this asymmetry the regulator might well impose some constraints to valuation methodologies and procurement principles to ensure that negotiations develop fair (cf. Mutale and Strbac, 2005). *Regulated bilateral arrangements* might be a better option under such conditions. Standardization of contracts is even more necessary under bilateral arrangements than in the case of market-based agreements for ancillary services.

Mutale and Strbac distinguish *cost reflective approaches* and *administered solutions* (Mutale and Strbac, 2005). In the former approach DG can pass through standard costs of providing service(s) to the DSO, while under the latter approach additional fixed regulatory rules about reward mechanisms and prices have to be adhered to. As regards the former method incentives to reduce the costs of service are lacking and also both parties have to reach agreement about the cost of service provision, whereas the latter method is “the least favoured by regulators and market participants alike” (Mutale and Strbac 2005: p. 78). The low popularity of such method is motivated by:
- the administrative burden upon market participants and regulators,
- concerns about the impartiality because of third party intervention in market operations,
- less flexibility with regard to service provision,
- problems with product innovation such as the inability to offer enhanced services.

**Application to specific ancillary services**

Reactive power supply, black start capabilities and islanding are by definition very locally oriented and should therefore be provided by a non-market based system. The same holds for services that can be provided by DSOs (via DG) as distribution network security, distribution voltage support and quality of supply related services (ILEX, 2004). Conversely, response and reserve services can be provided throughout the whole system, and would therefore qualify in principle for a market-based system (cf. Dispower, 2006). Yet regarding frequency response, many electricity industry analysts refer to the great challenge for (decentralized) market players to meet the stringent very swift response requirements and feel more at ease with mandatory regulation.25

More specifically, DSOs have the duty to guarantee frequency stability, recognizing the fact that balancing responsible parties can only be held to provide balancing but no frequency stability. Frequency stability in a certain area depends not on the effort of one balancing responsible party, but on the efforts of all participating parties. Therefore, the free rider problem is present in providing this service. Coordination by a DSO or TSO is absolutely necessary in order to make frequency stability possible by collective balancing efforts (Stoft, 2002). Coordination can be established by forming a balancing market, whereby ex-post deviations on the balancing programs are settled by an imbalance pricing system.

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25 See e.g. Eurelectric (2004), p. 23.
In the case of reactive power the free rider problem is also present, because users of reactive power pay too little without coordination. Moreover, reactive power is both cheap, compared to active power, and at the same time difficult to transmit. With long-term bilateral contracts reactive power can be provided to network operators, while at the same time some competition in the long term from new entrants is possible. Hence, even in the case of reactive power provision certain market-based options might be attractive, depending on regional/local network conditions. For example, in the UK reactive power is partly provided by a market-based tender process in which successful bidders are obliged to provide reactive power for the minimum period of a year.

Black start and operating in island mode are at first sight not attainable and profitable for DG operators. Yet, it is in their interest to start up the network as soon as possible in order to get money from providing active power, and consequently to supply reactive power as well. However, a precondition for being able to provide islanding and black start services is the presence of remote monitoring, control and communication infrastructure, which at the moment still is expensive. Therefore it might be more interesting for small DG systems to supply local services which do not need centralised optimisation, for example local voltage control, local frequency control and improvement of power quality.

**Different types of contracts**

There are different possibilities to remunerate DG for providing ancillary services to DSOs. Table 4.2 shows the payment arrangements for different ancillary services and for European as well as non-European countries.

**Table 4.2 Existing payment arrangements for ancillary services in selected countries and regions**

<table>
<thead>
<tr>
<th>Ancillary service</th>
<th>England</th>
<th>NORDEL ¹</th>
<th>Spain</th>
<th>California, USA</th>
<th>Argentina</th>
<th>Australia</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage control service</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Capacit y and use</td>
<td>For use, only if its provision is out of the mandatory limit</td>
<td>According to the range of absorption generation and time of response</td>
<td>According to capacity and use, only if its provision is out of the requested power factor</td>
<td>According to generators and transmission operators declarations</td>
<td>Payments for availability, enabling and compensation</td>
<td></td>
</tr>
<tr>
<td>Capacity and use</td>
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<tr>
<td>Only operation</td>
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<td>Capacity payment</td>
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<tr>
<td>Operation payment</td>
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<tr>
<td>Secondary frequency regulation</td>
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<tr>
<td>Capacity, operation (spot price) and compensation</td>
<td>Not considered</td>
<td>Not rewarded</td>
<td>Not specified</td>
<td>Availability payment (MW)</td>
<td></td>
<td></td>
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<tr>
<td>Only operation</td>
<td></td>
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<tr>
<td>Operation payment</td>
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<tr>
<td>System restoration (blackstart capability service)</td>
<td>Not considered</td>
<td>Not rewarded</td>
<td>Not specified</td>
<td>Availability payment (MW)</td>
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<tr>
<td>For equipment, availability and operation</td>
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<td>For capacity (MW) and operation (MWh)</td>
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<td>Capacity payment</td>
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<td>Capacity and use</td>
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¹ = NORDEL is a body for co-operation between the TSOs in the Nordic countries (Denmark, Finland, Iceland, Norway and Sweden).

Source: Raineri et al., 2006: Tables 2, 4, 6 and 8.

The table bears out that providers of ancillary services are often paid for both putting capacity at the disposal of the system operator and for actual utilization of this capacity to provide the ancillary service. Besides that it is also possible to remunerate DG with flat fees, option fees based
on availability, exercise fees based on utilisation and reduced (distribution) use-of-system charges (Mutale and Strbac, 2005). Option fees based on availability encourage the recipient of the service to pay for securing capacity, while exercise fees promote the actual usage of the service. The value of the provided service can also be added to the use-of-system charges, enabling the DSOs pass through the costs of these services to their customers.

4.5 Conclusions

Our preliminary conclusions are that the scope for revenue-enhancing provision of ancillary services by DG appears limited. Most scope seems to be in store for the provision of secondary and tertiary frequency regulation services to the TSO aided by DG aggregating actors as well as localised services such as the provision of reactive power and voltage support services. The value generating potential of these services seems to be dwarfed by that of power generation, with at times the provision of secondary and tertiary frequency regulation as notable exceptions depending on the design of balancing markets. Adoption of ANM may improve the prospects for DG to deliver local ancillary services to their DSO. Regulators should limit the scope for exercise of monopsonistic market power on the part of the DSO in procuring such services from DG.
5. Directions for alternative regulatory frameworks

5.1 Introduction

This chapter will present some broad directions for alternative regulatory arrangements without going into much detail. Possible alternative regulatory arrangements are manifold and can vary from minor modifications of current regimes to more radical shifts in regulatory practices. It is noted that this chapter sets the stage for the report of Joode et al. (2007), where selected alternative arrangements proposed here are further investigated in a quantitative framework.

As explained in Chapter 2 regulatory arrangements vary from one EU member state to the other. Yet, almost across-the-board European regulators do still largely ignore the phenomenon of rising DG penetration in regulation imposed on DSOs. So far only the UK has introduced some specific schemes that make explicit allowance for the DSO performance regarding the provision of access by DG to their networks and related innovative demonstration projects.

5.2 The financial impact of rising levels of DG on the DSO

Most EU member states are in transition from traditional regulation towards incentive-based regulation (IBR) or have already implemented IBR. Lately, quality-of-service tends to get more emphasis in European DSO regulation. Generally the evolution of demand for distribution network services by final power consumers is taken into account in interventions by EU regulators to curb DSO revenues and/or tariffs. Yet this is in stark contrast to prevailing tendency among European regulators applying incentive regulation to ignore the evolution of demand for distribution network services by DG operators. In doing so they appear to presume:
(i) A neutral impact of DG on the overall financial performance of DSOs during the regulatory period under review.
(ii) Any potential long-term positive and negative effects of incremental DG access to the DSO networks on DSO financial performance either are internalised by DSOs in their operational management or more or less fully offset each other.

Let us briefly consider these two points, based on findings presented in other DG-GRID reports.

The report of Cao et al. (2007) has prepared projections of the net cost impacts of rising penetration of DG in UK and Finnish distribution networks. Although the projected quantitative impacts varied notably between the two case studies, indications on the nature of the impacts of increasing DG penetration on the DSO network costs were quite similar:
• CAPEX on network segments at higher voltage levels of the DSO grid than the voltage levels at which DG facilities are connected is reduced by virtue of capacity expansion deferral. Reduced investments translate into lower depreciation allowances on fixed assets and hence lower CAPEX.
• CAPEX on the network segments of the DSO grid at the voltage levels at which DG facilities are connected rises hardly initially but rises more than proportionally fast at higher levels of DG penetration. On balance, at higher levels of DG penetration total CAPEX rise substantially. This tendency is somewhat mitigated when a DSO applies ANM as operational management: expansion/replacement investments in network components are deferred partly offset by replacement by more expensive intelligent components and ICT infrastructure.
• OPEX on account of distribution losses tend to diminish initially but to rise notably at higher penetration levels on account of increasing reversed power flows (from the DSO network to the transmission network) and increasing capacity utilisation rates of the lines and wires. This tendency is aggravated by application of ANM which at the margin relies more on in-
tensive use of existing assets through sharp real-time interventions rather than relying on redundancy through early network reinforcement under PNM.

- OPEX at high DG penetration levels also rise under ANM on account of curtailment payments to DSO network users at times when network capacity limits are being approached, notably DG foregoing revenues of curtailed generation.
- OPEX on behalf of O&M costs tends to rise on account of increasing complexity of grid operations and attendant needs to monitor the grid conditions more intensively and in more detail.

These results do not support the presumption of a neutral impact of rising DG levels on the short-term financial performance of the DSO. The report of Joode et al. (2007), which includes the DG revenue impact, provides further evidence to that effect.

Moreover, the typical DSO is hand-tied to apply a passive operational management philosophy. Sheer professional habit and unwillingness to have to rely on decentralised DG in a liberalised market framework instead of robust, largely n-1 contingency proof, network infrastructure is a major point in case. But also the operational conditions for applying active network management in terms of ICT infrastructure as well as required manpower capabilities are lacking. However, high DG penetration levels will render the operations of the DSO network more and more complex. Moreover, ignoring potential benefits of genuine integration of DG facilities as components of active network management will become increasingly untenable for DSOs.

It is noted, that the awareness among European DSOs is growing that revolutionary changes are imminent in the way their business will be conducted. Some DSOs have started to prepare themselves for the introduction of ANM through replacement of obsolete conventional network components with intelligent network components, investment in expansion of ICT infrastructure, small pilot projects on intelligent networks and enhancement of in-house staff expertise.

5.3 Options for changes in prevailing DSO regulation regimes in the EU

The basic conundrum facing the regulator is to determine tariffs that ensure that:
- All ‘reasonable’ demands for distribution network services are met.
- Set quality standards are complied with.
- The DSO is financially capable, and is disposed, to implement required investments and operational activities to meet these demands in an efficient way from a societal perspective and in compliance with pre-set quality standards.

The DSOs periodic income statement is determined by the balance of revenues and expenditures during the reporting period in accordance with prevailing accounting principles. In the previous section it has already been indicated how (increasing levels of) DG impacts on prevailing DSO business models. Let us assume in the ensuing that in the base case the regulator applies IBR with a revenue cap that does not make allowance for the evolution of DG in the DSOs network. If, as indicated in the previous section, this evolution has at medium to high DG penetration levels indeed an increasingly significant negative incremental bearing on the DSOs overall costs, the DSO has no financial incentive to voluntarily accommodate further DG penetration.

Let us furthermore assume that in the base case regime the building blocks approach and frontier benchmarking is applied.

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26 Based on (Jansen, 2006; Bauknecht et al., 2007.
27 By assumption the DSO is not able to levy deep connection costs on DG in both the base case and alternative regulatory regimes (see paragraph 2.1).
This base case will be the point of departure for an alternative regulatory regime governing DSOs which does make allowance for the DSOs performance in terms of network services to DG. The design of such alternative regulatory features would have to be inspired by the positive externalities of fast penetration of DG as perceived by the public sector in combination with the negative overall impact of such trend on the DSOs income statement under the base case regulatory regime.

What features should the regulator aim for when designing the alternative regulatory regime? The alternative regulatory regime would have to at least neutralise the negative total impact of (increasing) DG on the DSOs allowable costs. Perhaps the regulator should slightly more than offset this negative impact initially in order to overcome the deeply ingrained prejudices against DG among part of current DSO staff. Furthermore, the alternative regime should remove any existing biases against the introduction of ANM, so that the DSO can make an economic decision when weighing the pros and cons of ANM against PNM.

In principle, the following avenues are open to regulators to design the components of the alternative regime:

1. Allowance in the regulated asset base (RAB) and allowable OPEX.
3. Allowance through including of a factor in the productivity benchmark analysis.
5. Allowance by way of direct revenue driver (with possible network dependency).
6. Shift from building blocks approach to total expenditures (TOTEX) approach.
7. Shift from frontier benchmarking to average benchmarking.
8. Shallow connection charges in tandem with time-variable UoS charges with locational signals.

Let us consider these suggested options in more detail hereafter.

5.3.1 Allowance for DG in the RAB and allowable OPEX

The allowance for DG in the RAB of the DSO depends on the chosen benchmarking approach.

If a building block approach is applied (see Section 2.2), it is suggested to earmark justifiable projected investment costs that can be specifically attributed to network services rendered to DG and allow (the lion’s share of) these costs to be passed through in the regulated asset base. Earmark also justifiable projected operating expenses that can be specifically attributed to network services rendered to DG for inclusion in the approved OPEX in the first year of the regulatory period under review. Justifiable costs should be based on expert judgment and ex post information over the previous year(s).

If a TOTEX approach is applied, it is recommended to earmark projected total allowable DG-attributable costs per annum and allow renumeration of the DSO for the lion’s part of these earmarked costs, provided these costs do not exceed a certain maximum percentage of total projected annual costs.

5.3.2 Allowance for DG in quality of service regulation

The Q-factor with a bonus-malus character accounts for (over/under)compliance with standards regarding (1) reliability, (2) power quality associated with power outages and voltage disturbances, and (3) consumer satisfaction with service. To the extent DG can be considered to exhibit positive externalities, a similar factor could be introduced regarding the DSO performance.
regarding network services to DG. The DSO could be benchmarked against the peer average regarding indicators such as:

- # new DG connections.
- # DG MWh fed into the DSO network as a ratio of MWh consumed; this indicator could be made more sophisticated as an average score based on hourly (or shorter-interval) measurements.

It is acknowledged that DG feed-in is in major part dependent on factors beyond the control of DSOs. Still, including a proper DG-performance factor in the Q-factor may well entice DSOs to stimulate a more evenly spread of DG through differentiation in UoS system tariffs to be charged to DG.

5.3.3 Allowance through including of a factor in the productivity benchmark analysis

DG penetration can be considered as one of the inputs to the productivity benchmark analysis, which determines more or less the efficiency discount (X-factor)\(^\text{28}\). When a benchmark approach is followed by the national regulator, firms are compared to each other regarding their costs and, notably, their cost efficacy. The cost reduction that a firm should be able to achieve is based on an efficiency discount (X-factor), which is determined by the productivity change during that period\(^\text{29}\). The productivity change, or rather the reciprocal factor cost efficacy, is the variable that is compared between firms. It is usually defined as the mutation in the standardized economic costs divided by a standardized and composite output variable. This output variable contains cost drivers like customer numbers, units of electricity distributed, and network length.\(^\text{30}\) The composition of the output variable differs somewhat between countries. It can be considered to add the capacity of DG on the network or the units of DG electricity distributed as components defining the composite output variable.

5.3.4 Allowance for DG in the Z-factor

In benchmarking-based IBR, the X-factor is established on the basis of results of comparison of DSOs on historical productivity growth trends. By using productivity benchmarking, DSOs efficiency is determined only with regard to a few different input factors to preserve the explanatory power of the benchmarking analysis. As a result, outcomes of the econometric benchmarking analysis do not make proper allowance for other less important input factors and DSOs efficiency results have to be adjusted to account of these DSO-specific explanatory factors, so-called Z-factors or structural factors. Examples of Z-factors are differences between urban/rural network parts, network density/average length of lines (Norway), relative importance of river crossings (Netherlands), connection density (currently subject of discussion in the Netherlands), subsoil conditions, etc. DG volume indicators, whether or not subdivided by DG technology, may be considered as well as an adjustment factor. For example, DG volume indicators *inter alia* one the following parameters could be chosen: MW\(_{DG}\) connected, MWh\(_{DG}\) fed in.

5.3.5 Allowance for DG through direct revenue driver

In principle, the regulator may allow DSOs DG-related revenue on a €/kW\(_{\text{newly connected}}\)DG/yr basis. Newly connected DG units could for example be taken to refer to DG facilities connected in the current regulatory period. Besides or alternatively, it can be considered to allow the DSOs

\(^{28}\) Dependent of the chosen regulatory method the connection between productivity and X-factor is direct or more indirectly as the regulator takes the company specific situation into account.

\(^{29}\) In practice mostly partly the productivity change of the former regulatory period or some expected productivity change measure is used.

\(^{30}\) For UK, see Pollitt (2005) for some other countries Jamasb and Pollitt (2001).
additional revenue by an amount of a €/kWh$_{DG}$/yr. These revenue drivers should be calibrated to broadly reflect ‘average DSO’ DG-attributable incremental costs, not allowed for by other incentives. Moreover, it could be considered to make allowance for the tendency of higher DG-attributable incremental cost the higher the DG penetration rate.

This way, very cost-effective DG-integrating DSOs could earn surplus revenue. This type of incentive may not only make it more affordable for DSOs to accommodate DG, but may also stir cost-reducing innovation, as a comparative advantage in DG accommodation of DG under this type of regulation directly translate into higher DSO earnings.

5.3.6 Shift from building blocks approach to TOTEX approach
Both the building blocks approach and TOTEX have their pros and cons (see Section 2.3). In this context, one drawback of the building blocks approach should be highlighted, i.e. that it can introduce a significant bias against the introduction of active network management.

In Section 5.2 it was described how the introduction of ANM can have diverging impacts on CAPEX and OPEX. As CAPEX is not benchmarked under the building blocks approach there is an incentive to raise CAPEX. This incentive does not exist when applying the TOTEX approach. Therefore there exist a bias in building blocks for carrying out network investments (CAPEX) and applying passive network management instead of increasing the network capacity by active network management and increasing OPEX to some extent. In some cases, this bias may be smaller as DSOs may be subject to strong regulatory accounting rules which force them to provide the regulator with separate capital and operational cost data each year. Consequently, shifts between capital and operational costs might be more visible for the regulator and the bias correspondingly less. However, monitoring by regulators can be considered in general to be more loosely when the building blocks approach is applied as compared to TOTEX. As a result in building blocks regulation usually a bias to passive network management can be discerned.

In other words, when applying active network management the building blocks approach can put severe constraints on the DSO regarding the flexibility in raising operational expenses (whilst simultaneously lowering capital outlays), because only operational expenditures are benchmarked. As the capital expenditures are in many cases insufficiently checked and therefore rather sticky in downward direction, the bias towards passive network management may affect total costs (OPEX + CAPEX) in upward direction. The TOTEX approach puts the constraint on the total level of expenses leaving flexibility to the DSO as regards the CAPEX/OPEX proportions and has, at least in the latter respect, a more neutral impact on the choice of network management approaches.

5.3.7 Shift from frontier benchmarking to average benchmarking
There are two kind of benchmarking possibilities in incentive based regulation, DSOs can be benchmarked either against their peers i.e. performance of the whole national DSO sector or against the performance of the most efficient DSOs. The former way of benchmarking is called average benchmarking, while the latter is known as frontier benchmarking because the most efficient companies are on the efficiency frontier resulting from benchmarking analyses.

The choice of benchmarking method depends on both the phase of regulation and the number of DSOs pertaining to a country. Generally in countries where IBR is applied a tendency can be discerned of introducing frontier benchmarking in initial regulatory periods and shifting to aver-

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31 It can also be considered to use as an alternative or supplementary revenue driver the incremental DG energy fed into the DSOs network, compared to the average annual DG energy fed in during the previous regulatory period.

32 In Section 5.3 quality regulation is assumed and therefore pros and cons in the absence of quality regulation are not dealt with.
age benchmarking in later regulatory periods. At the start of incentive regulation the differences between firms are large and therefore the most inefficient firms have to catch-up. After a few regulatory periods, the differences between firms are small and both the risk of collusion and investor risks of frontier benchmarking compared to average benchmarking force regulators in some cases to introduce average benchmarking. The risk of collusion attributed to frontier benchmarking (Jamasb et al., 2004), however, is closely connected to the number of DSOs to be benchmarked. In case there are hundreds of DSOs (for instance in Germany and Austria), the risk of collusion between frontier and non-frontier companies is much smaller than in case of tens of DSOs (for example in the UK and the Netherlands). In the former there are several frontier companies so the number of implicit agreements between companies has to be much larger compared to the latter, diminishing the risk of collusion substantially. Concerning the investor risk, when frontier benchmarking is applied in many cases DSOs have little chance to exceed the efficiency of the benchmark during the regulatory period, compared to average benchmarking. This entails higher risks both to the DSO and investors. The latter will calculate higher firm-specific risk premiums and with that higher yields in return for providing capital (debt and/or equity) to the DSO.

Apart from the former reasons, average benchmarking is more favourable to network innovation as it is easier for DSOs to capitalize on the efficiency gains due to their innovation investments. DSOs investing in network innovation and developing competitive advantages vis-à-vis their peers have more certainty that they can benefit from such advantages under average benchmarking. After all, for obtaining higher profits it is easier to beat an average than to beat the top firms. For a DSO to beat the industry average his relative efficiency has to improve, for instance by successfully assuming the risks associated with introduction of firm-specific innovations.

5.3.8 Shallow connection charges in tandem with time-variable UoS charges with locational signals

In order to not discriminate against capital-intensive technologies in terms of the upfront financing barrier, transparent shallow connection charges are recommended. Yet the impacts on network costs of DG connection are quite location-specific. Hence, locational UoS charges are recommended. This applies both to DG and centralised generation. This is consistent with a regulation of the European Commission (see EC, 2003b and EC, 2007b) aimed at the transmission network level. In order to avoid discrimination among generators connected to different voltage levels, there is also a strong case for locational signals in distribution networks. More pressure should be exerted on EU MS to reconsider current industrial policy that implicitly favours centralised generation in regulatory competition with other member states. Moreover, incentives towards alignment of private with social objectives of DG generation management is introduced when time-variable UoS charging is made technically feasible and is subsequently implemented. Feeding in at times of high (low) local load should be encouraged (discouraged). At the same time, time-variable UoS charging stimulates the willingness to cooperate with ANM on the part of DG and may create opportunities to provide new information services for the DSO.

5.3.9 Responsibility for DSO of distribution losses with time-variable carrots and sticks

Regulatory features assigning more responsibility to the DSO for losses in his network are to be recommended as this will stimulate efficiency of DSO operational practices from a social perspective (see also Section 2.1). Introducing time-variable elements in such regulation, putting higher rewards (penalties) for losses below (above) a certain DSO-network-specific norm at

\[33\] Time-variable UoS charges induces DG to feed in his produce (to reduce production or retain his produce) consistent with the DSOs ANM objectives and broader optimisation of socio-economic value.
times of peak demand will further enhance the efficiency value from a social perspective. Again, it will also incentivise innovation in network management.

5.4 Conclusions

Departing from a specific base case IBR regime, the analysis in this chapter has yielded a number of recommendations regarding the broad directions for alternative regulation of DSOs. These concern:

- Allowance for DG in the regulated asset base (RAB) and allowable OPEX.
- Allowance for DG by way of a new component in quality of service performance regulation.
- Allowance through including of a factor in the productivity benchmark analysis.
- Allowance outside the benchmarking procedure (z-factor).
- Allowance for DG by way of direct revenue driver.
- Shift from building blocks approach to TOTEX approach.
- Shift from frontier benchmarking to average benchmarking.
- Shallow connection charges in tandem with time-variable UoS charges with locational signals.
- Responsibility for DSO of distribution losses with time-variable carrots and sticks.

In principle, all these regulatory approaches can be combined and together applied in practice. However, especially the first five measures may replace each other more or less. As an example, a combination of an allowance for DG in the regulated asset base and allowable OPEX, and an allowance by way of a direct revenue driver will be shown in Joode et al. (2007).

Finally it is noted that overall the DG GRID project has produced valuable new insights into regulation of DSOs. Yet in the framework of DG GRID no integrated analysis of the social net benefits of further penetration of DG was envisaged. Hence the question how far the penetration of DG should go from a societal perspective remains to be addressed. DG and notably renewables-based DG has significant externalities such as GHG emission mitigation and mitigation of long-term energy supply security risks. Yet DG GRID research results suggest that at high levels of DG penetration the incremental network costs can become quite large. Hence, depending on a range of conditions in the network service area it might well be that a certain socially optimal penetration level for DG exists. Furthermore, as has been pointed out in Section 3.3 the design of DG market stimulation instruments can have an important bearing on this. The optimal design of DG stimulation mechanisms should make due allowance for the time-variable impact on network integration costs. These issues call for an integrated cost-benefit analysis of DG. On the cost side, to establish just the comparative economics of distributed generation alone is not enough. The costs of network services needed to bring the produce of DG power plants to the end-users should be included in the comparison between alternative electricity generation technologies. Such analysis could lead to new insights and relevant policy prescriptions regarding both DG stimulation policy and the price of network services rendered to DG customers.
References


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