Fostering energy markets, empowering **consumers.**

The Future Role of DSOs

A CEER Public Consultation Paper

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INFORMATION PAGE

Abstract

The role of the Distribution System Operator(s) (DSO) has traditionally been well understood and defined.

Distribution system operators (DSOs) play an important role in a well functioning IEM. The DSOs are responsible for secure system operation but are also a market facilitator. In the coming years, there will be new opportunities for DSOs to deliver benefits to energy consumers and the energy sector in general. Retail liberalisation, demand-side response arrangements, new technology, and distributed electricity generation as well as gas distributed injection have meant that the role and culture of DSOs has changed over the last decade and will continue to change.

This CEER consultation paper considers different regulatory tools to reflect the current differences in DSOs activity profiles, unbundling and structural and technical issues, and does not seek to impose a single regulatory solution for DSOs across Europe.

CEER invites all interested stakeholders to respond to this public consultation through the dedicated online tool. The deadline for responses is **27 February 2015**.

Target Audience

European Commission, energy suppliers, traders, gas/electricity customers, gas/electricity industry, consumer representative groups, network operators, Member States, academics and other interested parties.

Keywords

Distribution networks, new activities for DSOs, tariffs, smart grids, data management, energy consumers.

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Related Documents

ACER documents

- Energy Regulation: a Bridge to 2025, Conclusions Paper, 19 September 2014

CEER/ERGEG documents

- CEER advice on the quality of electricity and gas distribution services, Ref: C14-RMF-62-04, 21 October 2014
- Ensuring market and regulatory arrangements help deliver demand-side flexibility, Ref: C14-SDE-40-03, 26 June 2014
- CEER draft advice on data management for better retail market functioning, Ref: C13-RMF-57-04, 3 December 2013
- Status Review of Regulatory Aspects of Smart Metering, Ref: C13-RMF-54-05, 12 September 2013
- CEER status review on the transposition of unbundling requirements for DSOs and closed distribution system operators, Ref: C12-UR-47-03, 16 April 2013
- GGP on Retail Market Design, with a focus on supplier switching and billing, Ref: C11-RMF-39-03, 24 January 2012
- CEER advice on the take-off of a demand response electricity market with smart meters, Ref: C11-RMF-36-03, 1 December 2011
- GGP on Regulatory Aspects of Smart Metering for Electricity and Gas, Ref: E10-RMF-29-05, 8 February 2011
- ERGEG position paper on smart grids, Ref: E10-EQS-38-05, 10 June 2010

External Documents

- THINK Final Report Topic 11: Shift, Not Drift: Towards Active Demand Response and Beyond, June 2013
- THINK Final Report Topic 12: From Distribution Networks to Smart Distribution Systems: Rethinking the Regulation of European Electricity DSOs, June 2013

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INTRODUCTION AND SUMMARY

Background

There are important challenges facing electricity and gas markets as the Internal Energy Market (IEM) transitions in order to meet the needs of large shares of low carbon energy production and arrangements for the provision and procurement of flexible response.

The role of the Distribution System Operator (DSO) has traditionally been well understood and defined. DSOs have been, and continue to be, responsible for the safe and secure operation and management of the distribution system. They are also responsible for the planning and developing of the distribution system. DSOs have also had core responsibility for data management (in most Member States) associated with use of, and management of losses on, the distribution system. Accordingly, the role of the DSO was broadly passive, with the only interactions being with suppliers as users of the distribution system, the Transmission System Operator (TSO) in terms of the interface with the transmission system and in some cases with consumers for safety or supply interruption reasons.

Distribution system operators (DSOs) play an important role in a well functioning IEM. The DSOs are responsible for secure system operation but are also a market facilitator. In the coming years, there will be new opportunities for DSOs to deliver benefits to energy consumers and the energy sector in general. Retail liberalisation, demand-side response arrangements, new technology, and distributed electricity generation as well as gas distributed injection have meant that the role and culture of DSOs has changed over the last decade and will continue to change in the future.

However, while the basic functional model is broadly the same (i.e. that of a passive grid manager) there are significant differences between DSOs across Europe. In particular, their activity profile can vary quite significantly, especially for metering operations and data management responsibilities. In addition to different activity profiles, there are still important differences in the degree to which different DSOs have been unbundled across Europe.

Moreover, further differences are observable in both structure and specific metrics such as:

- size (number of customers);
- voltage levels (for electricity DSOs) and pressure levels (for gas DSOs);
- direct or indirect connection to the transmission grid (or off-grid for small islands and remote valleys);
- network automation and smart metering; and
- level of RES and distributed generation penetration.

Accordingly and as a result of these differences, there is no one size fits all model for the regulation of DSOs. Therefore, in assessing the activities which DSOs may engage in in the future, national specificities must be taken into account. Thus, according to different national situations, different regulatory tools can be developed. Given existing differences in activity profiles, unbundling and structural and technical issues, there is not a single regulatory solution that fits all national cases.

This consultation paper considers different regulatory tools to reflect the current differences in activity profiles, unbundling and structural and technical issues, and does not seek to impose a single regulatory solution for DSOs across Europe.

In this paper, CEER has assumed that all DSOs are fully compliant with the unbundling requirements set out in the 3rd Package Directives.

We also build upon the commitments made by regulators, in relation to DSO regulation, in the ACER recommendation 05/2014 Bridge to 2025. This paper also builds on recommendations and advice made in previous CEER/ERGEG reports and recommendations.

Conclusions on DSOs in the Bridge to 2025

In September 2014, ACER published "The Bridge to 2025"[1] describing its thinking on the development of the energy sector and the role of regulation over the next ten years. [CEER contributed significantly to that document.]

The Bridge to 2025 outlines a number of high-level conclusions relevant to distribution systems - on demand-side response and flexibility[2], the role of DSOs and on the development of competitive retail markets across Europe. Regulators committed to taking the following action in relation to DSOs (gas and electricity) –

- To develop a framework which will identify of a list of core DSO activities. This framework will facilitate the development of potentially competitive services in areas closely related to their core roles;
- To develop a flexible "toolbox approach" for the regulation of DSOs, to be adopted according to nationally prevailing conditions, including a set of consistent options to ensure an adequate level of business separation of core DSO functions from potentially competitive activities;
- To develop good practice guidelines for distribution network tariff structures, which aim to enhance the efficient development and operation of these networks to the benefit of consumers;
- To develop good practice guidelines for incentive schemes (including output-based schemes) to encourage efficient innovation by DSOs in areas such as smart grids;
- To develop good practice guidelines on regulatory approaches for piloting the application of new technologies and techniques, and for encouraging efficient research and development;
- To develop recommendations for clarifying the distinct roles and responsibilities of TSOs and DSOs in order to strengthen cooperation and technical data exchange between DSOs and TSOs, as well as among DSOs; and
- To explore ways of ensuring that small consumers are properly protected and empowered, and that incumbent players (notably Distribution System Operators) do not operate in ways which foreclose or distort the potentially competitive market in flexibility services, including from the demand side.

[1] Energy Regulation: A Bridge to 2025. Conclusions Paper, 19 September 2014

[2] Ensuring Market and Regulatory Arrangements help deliver demand-side flexibility C14-SDE-40-03

Content of this consultation document and next steps

CEER welcomes views on the thinking presented in the present paper, and in particular on ways forward in the areas identified in the consultation questions.

This document addresses the following:

Chapter 1 examines the existing and future activities of the DSO, its core role, the facilitation of new markets and services, and areas where there is a need for further regulatory control.

Chapter 2 discusses the increasing involvement of DSOs in system operation with increased local generation and demand-side response, and the implications for the relationship between TSOs and DSOs.

Chapter 3 focuses on regulatory incentives to help bring about the changes needed, including some examples of how regulators are already doing this.

Throughout this consultation paper, a number of key questions are set out for consideration. These questions have also been listed at the end of this document for ease of reference.

Following the 8+ week consultation period, CEER will consider responses to this consultation carefully and prepare an evaluation of responses. We are also planning to hold a workshop with stakeholders to discuss key issues in each of the three areas covered by this consultation – the activities of the DSO, the DSO-TSO relationship, and incentives and charges. We will then publish a final report and take forward actions in the CEER work programme for 2015. These actions include a roadmap on regulatory initiatives relating to DSOs to implement the conclusions of our report.

We look forward to receiving stakeholder feedback via the dedicated online questionnaire on the CEER website.

1 The role of the DSO and need for regulatory oversight

The aim of this chapter is to explain the CEER view on the role of the DSO and the activities it may engage in. The chapter is structured as follows –

(i) principles that a DSO should follow;
(ii) a framework to help define, according to these principles, whether or not a DSO should conduct certain activities; and
(iii) a description of the main activities within this framework.

1.1 Principles for DSOs

Principle 1: The DSO must run its business in a way which reflects the reasonable expectations of network users and other stakeholders

The role of the DSO involves interactions with the TSO, with suppliers and increasingly with distributed connected generation, other DSOs, Energy Service Companies (ESCOs) and electric vehicle (EV) recharge providers, etc. Each of these parties are important stakeholders of DSOs and indeed DSOs will have differing degrees of responsibility and obligation toward these different stakeholders. DSOs should also ensure that they respond to the needs of new stakeholders and remove unnecessary barriers. CEER promotes the "consumer-centric model",[3] where the DSO should at all times act to improve consumer welfare and avoid unnecessary complication or confusion for consumers[4]. The same principles should be valid when engaging with other stakeholders listed along the supply chain. Such a model should also ensure that DSOs act in a manner that is in consumer's best interests.

Principle 2: The DSO must act as a neutral market facilitator in undertaking its core functions

As natural monopolies, DSOs are regulated and monitored by economic regulators in each Member State. To avoid market distortions through possible use of their monopoly power, DSOs should act as neutral facilitators of a competitive market or new commercial activities by both regulated and market parties particularly where the DSO has a role in metering and data management activities. If the DSO is part of a vertically integrated company or (unbundled) network group within which non-regulated and/or market-related activities are carried out, the DSO must not favour any activity by this group or part of this group.

This principle implies that:

a. the DSO must act in a non-discriminatory manner;
b. the DSO must not cross-subsidise; and

[3] GGP on Retail Market Design, with a focus on supplier switching and billing. Ref: C11-RMF-39-03

[4] CEER has also worked on the issue of the quality of services provided by DSOs to customers and published in October 2014 a"CEER Advice on the Quality of Electricity and Gas Distribution Services, focusing on Connection, Disconnection and Maintenance" Ref: C14-RMF-62-04

c. the DSO brand and communication policy should be clearly distinguished from the rest of the vertically integrated company/group to avoid confusing consumers.

It is important that *a level playing field* is established wherever possible where DSO activities have a direct or indirect effect on markets and market players. Even where there are factors that are not under the direct control or influence of the DSO, the DSO should still act in accordance with this principle.

Principle 3: The DSO must act in the public interest, taking account of costs and benefits

The supply of energy is an essential service on which most people depend and it is important that networks act in the public interest. Legislation and/or regulation may put obligations on DSOs to perform tasks that are not solely in the interest of the DSO in a business sense. Where a new public service obligation task is imposed on the DSO it is important that this task is subject to a comprehensive cost/benefit analysis, and that it is found to yield a net benefit to the energy consumers.

Normally, this cost/benefit analysis will be a matter for the legislative public authorities. In any event, it is important that where the DSO can demonstrate that it has efficiently discharged its public service obligations, the DSO be adequately remunerated by the regulator, and not exposed to undue risk.

Consultation question

1. Do you agree with these three core principles?

2. What challenges would new forms of stakeholders (e.g. community or municipal energy schemes and ESCOs) bring to DSOs and to existing approaches?

The areas above outline the core guiding principles through which DSOs should conduct their business, both in relation to their traditional core activities and any new roles. Whilst CEER recognises that DSO structures across the European Union mean that there is not one single model for a DSO and some DSOs will have enhanced roles in the energy sector compared to others, it is nonetheless the case that these three principles should apply regardless of the exact “specification” of each DSO.

These three principles are used in this paper to develop the framework upon which the roles of DSOs can be assessed and appropriate regulatory mechanisms developed.

1.2 Framework

The aim of this section is to provide a conceptual tool that can be used by policy makers and regulators to determine which tasks a DSO should perform in the future (both for electricity and for gas). Existing European legislation, national legislation or indeed regulatory rules may need to change to reflect the evolving role of the DSO or to enable new markets to develop. When there is the potential for competition to develop new activity areas, the default is to prohibit DSOs from undertaking the activity, or that conditions may be imposed where the activity is undertaken by a DSO. The reasoning behind this is that competition is considered to be the best means of meeting customer demands in the most cost efficient way. DSOs may be allowed to perform activities even if there is a potential for competition under certain conditions or regulatory controls, if there is a clear, specific justification. Examples of these conditions are limiting the level of engagement by the DSO, transparency requirements, a limited period for involvement in the new activity, or participation only when potential competition in a new market is relatively under-developed and limited participation by the DSO might help "kick start" the development of that market.

This results in the following **categories of DSO activities**:

I. Core activity

"Grey areas":

II. Activity allowed under conditions (no potential competition)

III. Activity allowed under conditions (potential competition, but special reason justifying DSO participation)

IV. Activity not allowed (potential competition and no special reason justifying DSO participation)

V. Activity forbidden (existing activity where competition exists)

This categorisation allows NRAs to determine if an activity should be allowed or not and if so, whether it should be a regulated activity or a non-regulated activity. Where it is not clear if a potential DSO activity falls into Categories I or V above or not, this framework allows for the activity to be assessed by the NRA under Categories II, III and IV (grey areas) in order to determine if the activity is a DSO activity.

Having noted that different conditions exist in current activity profile and unbundling structure of DSOs in different Member States, application of this framework to each potential DSO activity may lead to different results in different Member States in applying the proposed logical framework.

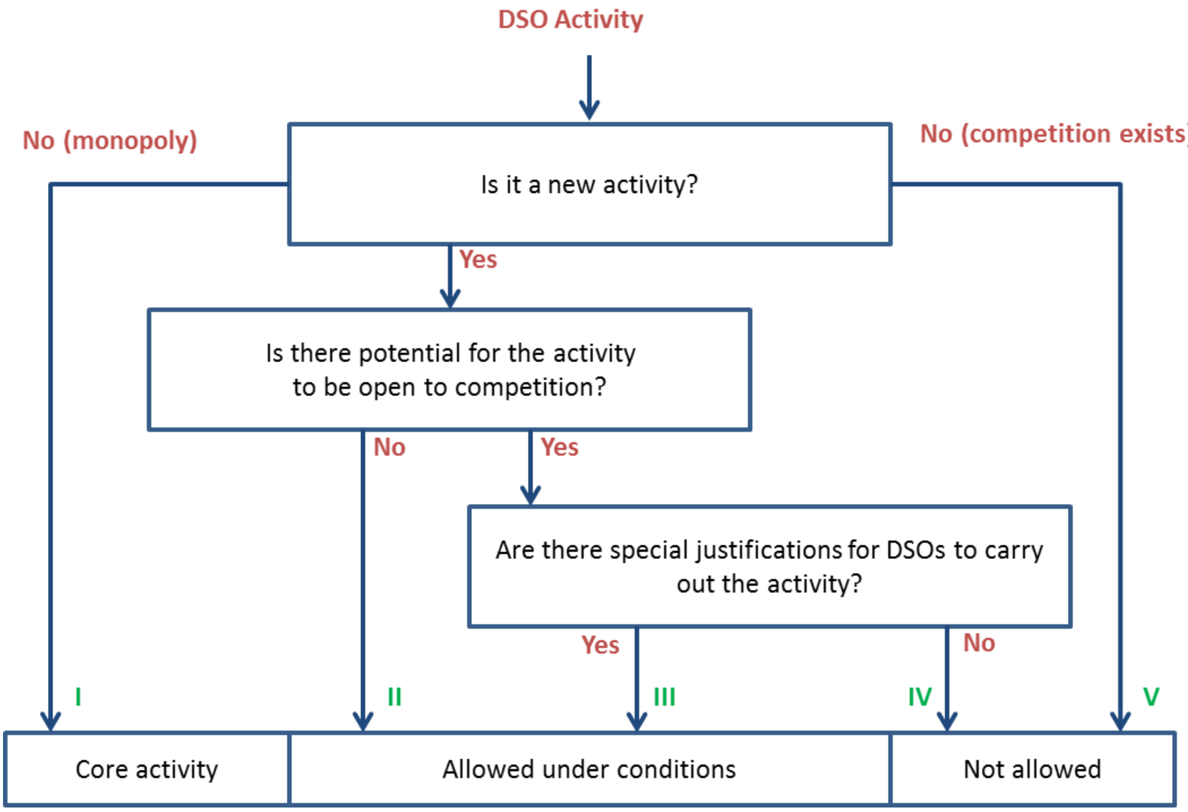

Figure 1 *- Logical Framework for DSO Activities*

Consultation question
3. Do you agree with the proposed logical framework? Are there other important questions which should be included in the framework?

1.3 Activities of DSOs

In this section, CEER provides its first thoughts on the list of activities that DSOs may or may not be allowed to perform within the future context in which they will operate. This list of activities should be considered in conjunction with the principles outlined in Section 1.1. In Annex 4, CEER has provide a table of possible DSO activities on which views are sought. Please keep in mind the codes attached to the activities discussed below when referring to Annex 4.

1.3.1 Existing and evolving core activities

Activities related to the (efficient) energy network infrastructure (A1), are the "core activities" of DSOs both for electricity and gas. These include planning, developing, operating and maintaining the distribution network; including ensuring sufficient capacity is available.

Connecting users to the grid (and disconnecting them upon their own request or because of safety and security reasons) is also a core activity. In the electricity sector, this entails connections of all network users (generators, prosumers and consumers). For the gas sector, on the other hand, *feed-in connections* are a new activity for DSOs, as the gas distribution network has typically operated only for top-down flows. In some countries, however, some traditionally core activities may be open to competition[5].

System security (A2) – (e.g. operating "traditional" load shedding) is also a grid activity. For electricity DSOs, "distributed generation (DG) shedding" will also fall under load shedding. DG shedding may be needed to cope with extreme situations with very low load and excess of feed-in from generation, which can cause new technical problems on the electricity grid (especially for protection systems) where normal market-based mechanisms have failed. For the gas DSO, more gas feed-in connections will require **gas quality checks (A3)** (according to gas interoperability specifications) at the entry-gate to ensure safety in gas usage.

The evolution of distribution networks towards active grids implies more **technical data management (A4)** than in the past, including TSO-DSO communication and also DSO-DSO information exchange (see Chapter 2). DSOs are responsible for managing all data associated with the operation and safety of the distribution system (with the exception of smart meter data in some Member States).

Managing network losses (A5) is also a core activity for the DSO, although we note that there are currently national differences in approach. Losses management includes incentives on DSOs to improve network efficiency by reducing actual losses. It can include any requirement on DSOs to buy/sell the energy necessary to cover network losses. Electricity network losses could, for example, be influenced by distributed energy resources (DER) penetration. In addition, the roll out of smart meters might provide DSOs with improved data to manage losses. This is an area which could require further attention from European regulators in future.

5 Some European countries have introduced competition in the market for connections to the existing gas and electricity network.

1.3.2 Activities where DSOs should not be involved

European legislation contains unbundling rules for DSOs[6] designed to ensure that there is no conflict of interest for DSOs in the delivery of their functions and no incentive for DSOs to carry out their activities in a manner which might favour certain parties over other parties in the competitive energy markets. Unbundling is a core pillar of European energy policy with strict rules around the areas of activity that DSOs can become involved in. Although there are different degrees of unbundling (see section 1.4), on a practical basis, these rules ensure that DSOs are not allowed to operate or have an interest in the businesses of **energy generation (B1)** and **energy supply (B2)**. Ownership unbundling ensures that the neutrality[7] of the DSO is an underlying feature in the delivery of all DSO activities. As set out in principle 2, this neutrality should remain a core feature of DSOs in the delivery of their functions.

There are further rules that govern instances when a DSO is not ownership unbundled and part of a vertically integrated undertaking. In particular, Member States must ensure that adequate business separation is in place and that the activities of the DSO are monitored by regulatory authorities, or other competent bodies, so that it cannot take advantage of its vertical integration to distort competition. As part of the business separation requirement (including management and information separation), according to the rules on unbundling, vertically integrated DSOs must not create confusion among consumers by using similar branding or identity as the supply branch of the same company (see principle 2).

DSOs may however, be called upon to play a role in facilitating the market for those who operate in the business of energy generation or energy supply. There may be some exceptional circumstances in which these activities, might be carried out (or facilitated) by DSOs (at least on a temporary basis). For instance:

- in case of disruption of the electricity transmission or distribution network, it may be necessary for DSOs to have an active role in **contracting local temporary generation for the sake of continuity of supply (B3)** even in off-grid conditions;
- **in case of gas emergencies**, DSO might be allowed to have **beyond-the-meter activities (B4)** such as verification of gas appliances before reconnecting.

These exceptional cases should not be confused with different, structural activities which should be prohibited. One example of structural activity that should be prohibited for the DSO is **"last resort" supply activity (B5)**. This relates to supplying consumers that do not have any supplier (for instance due to the liquidation of their supplier) or who do not manage to find a supplier that wants to supply them (for instance due their low credit rating). The only exception to this is where public service obligations, related to vulnerable consumers, may require a role for the DSO in supply, but only where the required supply has not been offered by or is not available from a supplier.

[6] Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, art. 26(1); Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in gas and repealing Directive 2003/55/EC, art. 26(1).

[7] Recognising that DSOs must act in the interests of their shareholders in respect of the DSO business

1.3.3 Activities where the DSO might be involved under conditions or subject to regulatory control

The following considerations are based on current European law and regulation, current experience on activities and our best current expectations about future activities.

DSO activities related to retail liberalisation

DSOs must have a relationship with retail suppliers (C1) in many countries in order to recover distribution network revenues. Retail liberalisation implies that DSOs should not normally have competitive commercial relationships with small end-consumers (domestic consumers and SMEs). Where DSOs are responsible for managing metering data, they may be requested to carry out certain activities to facilitate retail market functioning and competition. However, before doing so, regulators will need to ensure that the DSO is appropriately unbundled (as required under European legislation), that the appropriate controls and regulations are in place and that no market distortion occurs.

Unbundled DSOs may be requested/ required by suppliers to carry out certain actions in respect **of a consumer for revenue protection reasons**; for instance disconnection in the case of non-payment and prompt reconnection after payment. **(C2)**

The activities performed by DSOs, at a supplier's request, may also include switching a consumer to a new supplier **(C3)**. This activity is related to commercial data handling. DSOs must carry out these activities providing the relevant data in a non-discriminatory way to all market players. They should ensure personal data protection according to national legislation on privacy.

In many Member States, DSOs are responsible for **data management activities (C4)** This includes management of data needed for market functioning and refers not only to final consumers but also to distributed generation and storage units. Data management must be carried out in such a manner that data provided to market actors is delivered in a timely and reliable manner, in a standardised form and is up to date. Due to the importance of this issue and the principle of DSO neutrality, a specific section below is dedicated to this activity (see section 1.3.4).

DSO activities related to renewables penetration and new flexibility needs

The increasing volume of distributed energy resources (DER) connected to the DSO network means that there are different potential roles that DSOs may play. DSOs will be responsible for offering access to the distribution system, which must be delivered in a transparent and non-discriminatory manner. Typically, electricity DSOs will remain responsible for building the connection for the DER to the distribution network, although in some countries, building such connections is open to competition. Where the DSO is responsible for constructing DER connections, the importance of unbundling rules in preventing any potential conflict of interest with a generation party can be seen. This is particularly true where a DSO is part of a Vertically Integrated Utility (VIU).

Electricity DSOs will need to be able to monitor accurately the status of the grid in order to check, and eventually resolve, voltage-related (or even thermal, current-related) constraints. Gas DSOs will need to monitor gas quality issues more accurately.

As aggregators could provide some of the new demand response services described above, DSOs must not inhibit the development of competitive markets. Nonetheless, a DSO should be able to *use* flexibility services provided by demand response or small generators to solve voltage or capacity constraints on the network and to avoid or defer reinforcement if this is the most efficient option, providing that the flexibility is chosen in a non-discriminatory manner. In some cases, it may be necessary to develop incentives to ensure that DSOs choose flexible options ahead of network reinforcement where it is efficient to do so. Market arrangements will need to be developed in many countries for the offering and pricing of flexibility services. CEER is co-operating with ACER on this issue.

"System services" (see chapter 2) are traditionally the responsibility of the TSO, but this may also change over time. There could be room for DSOs to play a role in **"local dispatching" of local resources (D1)**. This may require a stronger level of cooperation with TSOs and even a higher level of unbundling.

In electricity, storage is considered, in principle, a market activity and therefore the **role of DSO in storage (D2) should be limited to the use of specific grid-oriented services**. However, energy storage cannot be used as a substitute for fully available distribution lines, but could be used to solve network constraints on a temporary basis. DSOs can use storage services, provided this technical solution is justified as the most cost-efficient option and is sourced in a non-discriminatory manner. The DSOs' role in storage will be considered again, once a market is properly developed for local, grid related services. In gas, we foresee fewer impacts on the network operation fuctions of DSOs and propose that the current arrangements relating to storage and linepack should remain unchanged.

DSO activities related to infrastructure provision for electric/gas vehicles (EVs/NGVs)

In the natural gas sector, infrastructure for fuelling gas vehicles is already common in some European countries. Gas fuelling stations are viewed as "network users" by the DSO and are normally run by a separate operator (service station operator). In the electricity sector, the range of different situations leads to potentially more complexity. EVs can be recharged at publicly accessible recharging points or, more frequently at domestic premises. In addition, there are different ways for recharging (slow, fast, very fast) according to the different level of rated power of the recharging infrastructure, while the level of DSO involvement in EV infrastructure development to date has differed across Member States.

CEER is aware of the "Alternative Fuels Infrastructure Directive**"** (AFID) and its imminent adoption, following first reading approval at the European Parliament. Under this new Directive, DSOs must **operate in a non-discriminatory manner towards any other person who owns and operates EV recharge infrastructure (E1)**. The AFID clearly states that ownership and operation of EV recharge infrastructure (in public places) is a competitive activity. This implies the EV recharge operator should be a separate company from the DSO.

However, DSOs do have an important role for the **development of EV recharging points as well as NGV fuelling infrastructure (E2)**. Firstly, the deployment of new service stations may require network development or reinforcements. Secondly, for better management of their grid, DSOs should monitor the usage of service stations; monitoring EV recharging points to offer financial incentives which, from a smart grid perspective, could help in future to smooth peaks and to avoid constraints. This does not mean that DSOs should directly operate the recharging points, only that DSOs and recharging points owner/operators should interact easily, and that consideration should be given to where recharging points are located on the DSO network.

DSO activities related to ownership & management of meters

Activities such as **owning and managing metering equipment (F1)**, are carried out by DSOs in most European countries. However, this is not the sole model. Alternatively, a **market driven approach** is possible **(F2)**, **where metering activities are carried out by separate, independent meter operators**. Market processes differ depending on the ownership of the meter.

DSO activities related to energy efficiency

Contributions to improved energy efficiency can be delivered across all aspects of the electricity and gas supply chains, from generation/production, through to transmission and distribution network transportation and demand-side management and response. Accordingly, DSOs should have a role in delivering activities related to energy efficiency, but this role should be limited to activities to **improve energy efficiency of the network (G1)**. In a liberalised retail context, DSOs should not to carry out **activities reaching beyond-the-meter (G2)** (e.g. into consumers' homes, etc.), outside of their core functions because there is scope for competition. This includes added-value offers such as services integrated with electricity/gas supply contracts. However, there may be value for the network from consumer energy efficiency measures that avoid network reinforcement and consumers could be rewarded for this. For example, in Member States where the regulator sets only allowed revenues, allowing the DSO to design distribution tariffs applied to its network users, the DSO might be allowed to set distribution tariffs, which can influence consumer behaviour and promote energy efficiency in the home and could provide benefits on the networks (see chapter 3, sections 3.2 and 3.4).

Providing advanced devices and added-value services for energy efficiency (G3), including displays for consumer awareness, should be considered primarily as commercial activities related to supply and not to distribution. Even though DSOs do not provide energy efficiency services, they should be able to raise awareness and incentivise efficiency in final consumption. Therefore, according to the above framework, any further involvement of DSOs in this activity would need to be justified on a case by case basis. However, in these instances where the energy efficiency is supply related, the DSO should not be restricted from incentivising consumers as long as the DSOs act in a neutral manner and do not impact on retail competition.

Other activities beyond the electricity/gas supply chain

Many other activities border the DSO's core role and must be examined within the framework proposed. Among these, are:

- **offering services to telecom companies (H1)**: electricity infrastructure (and to a lesser extent, gas infrastructure), can be used to host part of telecommunications (TLC) networks (both devices or lines, i.e. optical fibre wires). In a more advanced context, grid operators may obtain a licence as a telecom operator and resell IT services;
- some **public electricity-related services (H2)** like public lighting, traffic light operations, etc.: in some Member States, the same legal entity carries out not only distribution of electricity but also some of these services. Where this is the case,

accounting separation should be a minimum requirement. The same can happen with other **energy-related services (H3)** like district heating for gas distributors;

- **sharing smart metering infrastructures (H4)** in order to create synergies and economies of scale, especially for TLC services, for different utilities operating in the same geographical area ("smart city" approach).

In most cases, these "multi-utility" activities can be properly regulated through accounting separation, but in some cases, stronger unbundling requirements may be required.

Consultation questions
4. Do you agree with the proposed assessment of activities and are there any additional grey areas for DSOs other than those considered?
5. For activities falling in category II and III (see Figure 1), under which regulatory conditions could DSO intervention be allowed?

1.3.4 Access to data and data management

The role of the DSO in technical data management (A4) on the distribution system has been described as a core activity. However, in some Member States, DSOs have access to data beyond just the technical data which is needed for the secure, safe and reliable operation of the distribution system. Besides distribution system technical data management, **commercial data management (I1)** to coordinate the needs of different market actors in a changing future energy market[8] can be an important role for DSOs in many countries.

During the second quarter of 2014, CEER ran a public consultation on a "Draft Advice on Data Management for Better Retail Market Functioning"[9]. In this draft advice, CEER recognised that the arrangements for data management across EU Member States might vary significantly. However, CEER identified a number of recurring principles that are important to maximising the opportunities that the availability of customer meter data presents whilst minimising the associated risks (Privacy & Security; Transparency; Accuracy; Accessibility; and Non-Discrimination). As part of CEER held a public hearing on these issues on 22 September 2014; the final CEER Advice is expected to be published at the beginning 2015.

[8] For the purpose of this document, we use the term "commercial data management" to broaden the definition of "customer data management" to include not only final consumers but also distributed generation and storage units.

[9] CEER Draft Advice on Data Management for Better Retail Market Functioning, Electricity and Gas; Ref. C13-RMF-57-04

Indeed, the arrangements for commercial data management across EU Member States might be different. DSOs, in some Member States, may have access to significant types and volumes of commercial data, some of which may be important for the DSO in carrying out its activities (either core or grey areas) and some of which may be important, in particular, for supply companies or others operating in the competitive areas of the energy market. This applies not only to the communication between DSOs and network users but also to the exchange of data across all stages of the energy value chain. Changes in generation and consumption patterns and the greater need for flexibility may require increased coordination of information to aid security of supply.

Access to data

It is important to differentiate between technical data and commercial data. Technical data such as aggregated consumption and feed-in profiles; energy flows in the network and voltage profiles and interruptions will continue to be considered essential information for the system operators to allow them to manage their grid. Commercial data such as individual consumption profiles should be treated separately from technical data. There must also be special regard to consumers, who must be free to agree or disagree on how their personal data is used.[10] Appropriate data protection and privacy measures must be in place to protect the consumer[11]. **Data collection for system security**, including potentially grid planning, operation and maintenance will be anonymised so that it adheres to data privacy conditions **(A2).** Both types of data will be needed by different parties for different uses and should be in a common format. There may be instances where the DSO can give access to trusted parties who have been authorised by the customer to directly collect such data, but this should be subject to strict controls.

In terms of responsibility for commercial data management**,** Expert Group 3 of the European Commission’s Smart Grid Task Force presented three models for data management in 2013[12]: The three models were:

- **DSO As Market Facilitator:** *The DSO as market facilitator case favours a model based on a data hub, which is the standardised centralised or decentralised point for the market parties to collect all operational data as well as all necessary data to facilitate the market (data about customers, their technical possibilities, and their consumption or production). The DSO provides this data to the market via the data hubs, as a regulated neutral market facilitator in a non-discriminatory manner.*
- **Third Party Market Facilitator - Independent Central Data Hub:** *This case consists of an independent central communication platform based on one or several data hubs which will interact with different smart grid stakeholders, potentially storing data and processing it. This will allow equal access by all market participants to commercial data facilitating the market in a neutral manner, as the third party is by definition an independent one.*

[10] GGP on Regulatory Aspects of Smart Metering for Electricity and Gas. Ref: E10-RMF-29-05

[11] See Europeam Commission Recommendation of 10 October 2014 on the Data Protection Impact Assessment Template for Smart Grid and Smart Metering Systems (Official Journal of the European Union, 18 October 2014)

[12] http://ec.europa.eu/energy/gas_electricity/smartgrids/doc/xpert_group3_first_year_report.pdf

- **Data Access-point Manager (DAM):** *The DAM case foresees the creation of a commercial role that shall be played by certified companies who act as a data gate keeper providing data access to any certified market player and/or consumer/prosumer. This Data Access-point Manager would be designed to enhance existing market structures, roles and responsibilities and would not necessarily change them.*

Regardless of which model, or variation of a model, is employed by Member States for data management, CEER believes it is essential that the DSO should not engage in any activity that would negatively impact the competitive market.

Each model has its own associated benefits and costs. Whatever the approach to data collection, the provision of data should be carried out by a neutral body to ensure competition by ensuring consumers can switch suppliers easily, and that ESCOs and suppliers do not have barriers to information access. If a DSO acts as a data hub, it must be independent from interests of its vertically integrated undertaking. The best way to ensure this is full ownership unbundling for this DSO although strict supervision of DSO activities within other unbundling models can also ensure sufficient independence and market confidence.

There must be clear rules governing the exact responsibility for **data management (I1)** – collection, processing, storing and forwarding. It is essential that the appropriate data privacy, security and protection measures must be in place. CEER's March 2014 data management consultation document[13] discusses in detail data management for better retail market functioning.

Consultation questions
6. Do you agree with the assessment of DSO access to data and data management?

1.4 DSO separation

The changes in the energy sector and the new markets and services which are developing mean that there may need to be further regulatory or legal controls on DSOs, in addition to the current unbundling rules.

There are different levels of DSO separation, the main types of unbundling being: accounting, functional, legal and ownership separation[14].

- Full ownership unbundling (ownership separation) is where the DSO is a separate company to any interests in generation or supply;
- Legal unbundling is where the DSO is a legally separate entity with its own independent decision making board, but remains within the umbrella of a VIU.
- Functional or management unbundling is where the operational, management and accounting activities of a DSO are separated from other activities in the VIU; and

[13] Data Management for Better Retail Market Functioning Ref: C13-RMF-57-04

- Accounting unbundling is where the DSO business unit must keep separate accounts for its activities to prevent cross subsidisation, from the rest of the VIU.

While full ownership unbundling is considered to be the strongest model for the independence of the DSO, the other models can also ensure transparent and independent decision making and equal treatment of all DSO stakeholders, as long as sufficient ringfencing and regulatory monitoring and oversight are in place.

The degree of separation (the most effective being the ownership unbundling) from VIUs will influence whether the DSO is allowed to undertake activities that are listed in the 'grey' area of the framework under certain conditions. The more DSOs engage in flexibility and DSR, the more robust separation is needed, especially if the DSOs also have a role in data management.

Further separation from other market participants

The DSO may need to have an increasing role in system operation; this point is discussed in the next chapter. The more responsibility the DSO has, the greater the potential need for further separation of its system operation activities from other competitive activities carried out by other companies of the same VIU (like supply and generation).

More generally, if the DSO takes on new roles, sufficient controls are needed to ensure that DSOs do not use access to data to gain commercial advantage or create market distortions**.**

De-minimis threshold

The current unbundling rules are applied with a *de-minimis* threshold of 100,000 consumers[15] for DSOs. The number of DSOs with fewer than 100,000 connected consumers varies across Europe. In 2013, CEER published an initial review of the status and real implementation of unbundling requirements placed on DSOs under the 3rd Energy Package.[16] Consequently, there may be value in further work to understand how many final consumers are connected to these networks. All European customers, whether they are connected to a bundled or undundled DSO, should be able to benefit from the 3rd Package without discrimination. If a DSO is carrying out activities identified as 'grey areas', it should be subject to strict unbundling requirements regardless of whether or not it is subject to the *de-minimis* rule. Furthermore, as the role of some DSOs develops into an active grid manager, it may be worthwhile to reconsider the application of the (current) *de-minimis* rule and if it is still appropriate. Such review could entail either the adaptation or the decrease of said threshold.

[15] "Member States may decide not to apply paragraphs 1, 2 and 3 [of Article 26] to integrated electricity undertakings serving less than 100 000 connected customers, or serving small isolated systems" Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, art. 26(5); similar provision in the Gas Directive for gas DSO as well.

[16] The review was based on an internal survey completed by 24 of the 31 NRAs (which are CEER members or observers). This review was based on information available in Summer 2012. For further information: CEER, Status Review on the Transposition of Unbundling Requirements for DSOs and Closed Distribution System Operators, C12-UR-47-03 April 2013.

Given the variety in DSO structure, size and activities in different Member States, a more flexible approach could be considered for the *de-minimis* rule. It may no longer be appropriate that a single number (100,000) is the threshold for the *de-minimis* rule across all Member States. Indeed the CEER Unbundling Status review found that in many countries only a small share of a country's DSOs serve more than 100,000 connected customers and are hence legally required to be unbundled.

It is more important to develop a new, more flexible concept for the *de-minimis* rule, which is based on the number of customers in a country that are connected to a DSO that is covered by the *de-minimis* rule. For example, in some countries there may be many small DSOs with less than 100,000 customers, however, because of the number of such DSOs, the percentage of consumers served by such DSOs is quite high. In other Member States, the number of customers served by DSOs below the *de-minimis* rule may be not-existent or very low. Adapting the *de-minimis* rule to the specific structural conditions existing in each Member State could help in ensuring that only truly marginal situations are covered by this rule.

Consultation questions

7. Do you agree that the risk of DSOs participating in some of the 'grey areas' (particularly flexibility and DSR) decreases the more separated a DSO's operational activities are from other competitive activities carried out by other companies within the same vertically integrated group?

8. Do you agree with first considerations on the de-minimis *threshold?*

2 DSO-TSO relationship and responsibilities

As stated in the introduction, the traditional role of the DSO is evolving. Some DSOs are becoming active grid managers, much as TSOs already are, rather than being passive recipients of energy from the transmission system. In order to actively manage their distribution grids, DSOs will require system services and flexibility to maintain a secure, high-quality service. This implies that DSOs, especially larger ones directly connected to the transmission grid, will need to coordinate more frequently with the TSO. A coordinated DSO/TSO interface may be required to ensure that the necessary information exchange can take place in a systematic manner.

Network codes on balancing for gas and electricity already propose a greater cooperation between DSOs and TSOs. This chapter identifies additional areas where it will be increasingly important for the DSO or TSO to have access to information which they currently do not have (or do not have in a timely manner) and to improve coordination to facilitate a more systematic exchange of information. This chapter also investigates areas where it may be efficient for the DSO to have devolved responsibility for certain activities that today are carried out by TSOs only. Consideration will be given to TSO-DSO coordination, especially for larger DSOs, directly connected to the transmission grid. In particular, this improved coordination, should make both TSOs and DSOs more focused on responsiveness towards all network users: residential, commercial and industrial consumers, producers and prosumers, and future storage operators.

This evolution is currently more evident in the electricity sector. This will therefore be the main focus of this chapter; but in the relatively near future, it could become a reality also for gas, with the development of local gas injections (e.g. biomethane) on a large-scale. Interactions between gas and electricity may also require greater co-operation between gas and electricity TSOs and DSOs, for example in respect of managing high penetrations of PV and their associated very steep ramp rates.

2.1 Real-time grid operation

Services

As local generation increases (in particular non-synchronous generation sources, such as wind and PV), the traditional ways of managing voltage control carried out by the DSO and TSO may no longer be enough or may need to be supplemented with additional controls. Other issues such as congestion management (through redispatching, in case of meshed HV networks, or through curtailment, in case of radial MV/LV circuits) can also become increasingly relevant for distribution networks.

Currently, the DSO normally does not curtail DG to alleviate congestion – unless required to do so by the TSO for system security reasons. However, increased levels of DG and increased congestion on the distribution network may entail the DSO having a more active role in temporary congestion management on the distribution network, especially at MV and LV level. Finally, the DSO will face the challenge of power flow management, which will be more dynamic, i.e. characterised by imports and exports to and from the distribution grid.

Coordination

More frequent procurement of system services (e.g. active power modulation, reactive power compensation, active voltage control, congestion management) may be required by the DSO. An agreed operational framework between the TSO and DSO for the DSO to undertake this activity, as well as the coordination at the interface point, is needed.

Improved communication and data exchange would allow for real-time operation for both the TSO and the DSOs and facilitate greater involvement of distributed energy resources – DERs, including storage and demand response from consumers or from EV recharging stations – in system balancing. However, in many European countries there is currently no consistent or systematic exchange of information between the DSO and TSO regarding distributed generation and other DERs.

Coordination is also important in order to ensure that the TSO and DSOs maintain operational security. For example, the DSO should be informed when generation or demand connected to the distribution network is activated on the balancing market, as it may lead to constraints on the distribution network. Symmetrically, the TSO should be informed by the DSO in cases where the latter activates local ancillary services on its network which may impact the TSO activities.

Optimisation

At present, DERs often cannot supply their services to the system when needed and, in extreme cases, (renewable) energy production is lost due to necessary curtailment by network operators. In the future, there may be scenarios where the lack of DER coordination may negatively impact the efficiency of procuring balancing resources.

TSOs and DSOs might need to use the same DER service and it may be more efficient if one operator is prioritised over the other. Increased coordination and information provision will require a framework which sets out if and when it may be appropriate for the DSO to act in a devolved role to meet overall system needs efficiently (with TSO oversight). A rule of the framework may be that the party that would gain the most value from the resource has the priority in its usage.

Some network services are local by nature (e.g. management of voltage constraints by reactive power provision), while others are for the system as a whole (e.g. frequency response through active power modulation). Because of the different nature of network services, the role of the DSO and the framework for prioritisation of resource use are expected to be different. In the presence of markets for services with a predominantly local nature, there could be a greater possibility for a single market player to have a dominant position. Imposing minimum technical requirements and obligations for DER connections could constitute a solution to manage some types of these local services.

2.2 Balancing

As the need for active network management grows to cover a large proportion of distributed resources, there will be an impact on system balancing. If consumers and small generators are called upon to provide a response in real time or close to real time, the TSO's ability to balance the system is impacted by the amount of actions undertaken on the DSO network.

This might lead to a devolved role for the DSO, under TSO oversight and coordination as outlined above. Questions arise as to a devolved role for the DSO in balancing the system (for instance, larger DSOs having to balance their own systems to an extent) which would reduce costs as opposed to centralised balancing.

It has been found that, in general, the information exchange amongst the network operators with regards to scheduling and dispatch is insufficient in the majority of systems. In most cases, for the transmission system, the TSO ensures that market schedules are not in conflict with network operation. Increased information exchange may be required in the future to ensure that distribution network operation is not in conflict with transmission network operation[17].

2.3 Forecasting, network planning and development

Forecasting

Traditionally, the TSO has managed forecasting for scheduling and dispatch. In the past, DERs were negligible and therefore were not considered by the TSO with sufficient detail in the forecast. However, with increased levels of both DG and active demand, the DSO may be integrated into the TSO forecast, providing information concerning the forecast, scheduling and dispatch of distributed resources, taking account of distribution network constraints.

Although in general the TSO is still responsible for decisions, in some countries (especially those with higher levels or RES penetration), DSOs are progressively carrying out forecasting activities. Accurate forecasting at local level would help DSOs to manage congestion and voltage constraints. It may be more efficient for the DSO to have a devolved role in forecasting in the future. As a result a systematic data flow will be required as acquiring this information in real time is essential for TSOs.

Network Planning and Development

DSOs will also need to act in a transparent and non-discriminatory manner in offering connection terms to customers. The intermittency, typical of RES-based DG can jeopardise network stability if not dealt with properly. System operators may need to take on a co-ordinated approach to network planning and development.

Increased coordination and data exchange between DSOs and TSO for infrastructure reinforcement and development planning could lead to efficiencies and cost savings for the end consumer. In some instances, planned reinforcements on the transmission system may mean there is less need for reinforcements on the distribution system. The increase of network operators' use of telecommunication services will require greater coordination and even regulation in order to decrease costs and guarantee a proper cost allocation in vertically integrated structures (both OPEX and CAPEX) for the system. TSO-DSO sharing of telecommunication infrastructures requires specific interoperability criteria.

[17] The Network Code on Electricity Balancing acknowledges the role of the DSO in Art 26(1) "each TSO shall coordinate with other concerned TSOs and concerned DSOs."

Coordinated system planning could lead to smarter infrastructure investment and would require more coordination between the TSO and the DSO.

It is important that the same planning standards are applied and enforced evenly across the DSO and the TSO networks. Standardised planning requirements will ensure more effective operation of the grid and possibly alleviate some technical issues.

2.4 Emergency and restoration

The future European Network Code on Emergency and Restoration (NC ER) will outline the procedures and remedial actions to be applied in emergency, blackout and restoration states. This NC will deal with information exchange and procedures between key parties in these situations. Although the TSO is ultimately responsible for emergency operations, this NC will clarify whether the DSO can and should take a more active role in informing the TSO or taking actions in the absence of an instruction from the TSO. In order to ensure system security, there may also be a need to complement traditional load shedding protocols with new embedded generation curtailment protocols, in order to cope with low-load hours (for instance, sunny days or windy nights). In some countries with high RES penetration, these protocols have been already defined with the regulator's involvement.

2.5 DSO-DSO coordination

In electricity networks, the boundary between transmission and distribution in terms of operated voltage level covers a wide range. The voltage levels operated by DSOs differ from a maximum of 20 kV up to a maximum 200 kV and even higher in some exceptional cases[18]**.** In countries with many DSOs, some large DSOs operate a network of a large region with different voltage levels. Smaller DSOs mostly operate local networks with a lower voltage level up to 20 kV. The distribution networks of larger DSOs are usually directly connected to the transmission grid, whilst many small DSOs are only connected indirectly to the transmission grid via distribution grids of other larger DSOs.

Many Member States have a large number of DSOs meaning significant DSO to DSO interfaces. In these instances, increased DSO-DSO cooperation can lead to a more efficient network development and to a full utilisation of DER. In fact, in the future an increase of DER connections on low voltage networks will likely impact small DSOs as well. An obligation for DSOs to cooperate with neighbouring DSOs should also be considered.

Providing for standardised planning requirements and procedures across small DSOs, not directly interconnected to the transmission grid, and neighbouring larger DSOs, directly connected to the transmission grid, could help to avoid the entrenchment of small local solutions. However, caution should be exerted in relation to smaller DSOs who may be not fully unbundled. In these cases, regulatory authorities should assess if and to what level coordination at a DSO-DSO level is appropriate.

[18] THINK Final Report Topic 12 – From Distribution Networks to Smart Distribution Systems: Rethinking the Regulation of European Electricity DSOs, page 10.

2.6 Regulatory changes

Well structured, systematic information exchange will be necessary to ensure that both the TSO and the DSO have all the relevant information, as close to real time as possible, in order to maintain network stability. In order to do so, TSOs and DSOs need to develop clear definitions of hierarchical procedures and grid management plans with regard to one another and also to the market. It may be necessary to define new DSO/TSO responsibilities and governance arrangements as TSO and DSO grid management decisions have an effect on each other, but also on market players.

Depending on the level of DG penetration and RES integration in each Member State, and according to the size of DSOs directly connected to transmission grid, the role required by the DSO may differ and therefore interaction with the TSO may differ. However, a large volume of DG could affect the stability of the European grid and requires European general principles to tackle it. Any measure taken at the European or national level will need to address greater system operation interactions between DSOs and TSOs in terms of respective obligations and coordination requirements. Contractual arrangements or regulatory frameworks should be considered depending on the type of interaction.

Although significant work has been undertaken in the current Network Codes[19] to outline the roles and responsibilities and interactions between the DSO and TSO, further regulatory guidelines may be required in light of the increase in intermittent DG.

Consultation questions

9. Do you consider all the activities and topics described in this Chapter as relevant to further defining a regulatory framework for DSO-TSO relationship and responsibilities? Are any activities or topics missing in the DSO-TSO relationship discussion?

10. Do you agree with the description of the activities and topics in this Chapter? If not, what is your view on your specific activity or topic that is relevant for the DSO-TSO relationship?

11. Do you agree with the statement that further regulatory guidelines may be required (in addition to current Network Codes) and if so, which regulatory guidelines do you consider necessary?

[19] Such as the Demand Connection Code, Load Frequency Control and Reserves, Electricity Balancing and the Requirements for Generators and Operational Security. Similar provisions are provided in the Network Code on Gas Balancing of Transmission Networks (in particular Art 39 regarding “Information obligations of distribution system operator(s) and forecasting party(-ies) towards the transmission system operator”).

3 Economic signals for DSOs and customers

Companies who own and/or operate gas and electricity networks are natural monopolies, and NRAs regulate them in order to protect the interests of consumers. More specifically, NRAs approve or define the overall revenues which DSOs can earn from final network users in order to cover the costs of network development, network operation & maintenance and internal DSO operation costs. NRAs also approve the network tariff structures, and in some Member States, the network tariffs to recover these allowed revenues.

This chapter discusses how regulation might be further developed to encourage and incentivise, on one hand, DSOs to better discharge their evolving role of neutral market facilitators and, on the other, consumers to modify their behaviour taking account of economic signals for improved energy efficient consumption patterns.

The chapter builds on the ACER "Bridge to 2025" report, the principles set out in Chapter 1 as well as on the work already carried out in this area by CEER, including recently, a status review assessing how Member States encourage innovative solutions in electricity networks[20]. This chapter examines incentives for DSOs in order to encourage efficient outcomes, including demand-side response.

3.1 Price control related incentives

When setting price or revenue control allowances, NRAs have developed a wide range of incentive mechanisms. These have generally focussed on reducing costs of DSOs, promoting efficiency or delivering key objectives (e.g. improvements in performance against quality of supply metrics or delivery of a more innovative culture in DSOs).[21] In the context of changing technologies and changing market requirements, it is important that DSOs, within the scope of their proper role, play their full part in facilitating necessary changes.

During the recent consultation of the Bridge to 2025,[22] some stakeholders responded that the traditional regulatory framework does not adequately address investments in research and development (R&D) and innovative trials. These new types of investment, it is argued, have a riskier profile than conventional network investments even when they are protected by a regulatory framework. These innovative investments are often referred to as smart grid investments.

The extent to which the risk is borne by the DSO and/or the end customer will depend on the specific regulatory decisions in each country.

[20] CEER Status Review of regulatory approaches to smart grids, Ref: C13-EQS-57-04

[21] CEER 5th Benchmarking Report on Quality of Electricity Supply, Ref: C11-EQS-47-03

[22] Public Consultation on European Energy Regulation: A Bridge to 2025 Ref: PC_2014_O_01

Drawing on the typologies of investment risk[23] referred to in the ACER Recommendation n.º 03/2014 on incentives for Projects of Common Interest, it is important to seek to identify what particular or incremental risks are characteristic of innovative investments compared to conventional distribution investments.

Consultation question

12. What, if any, are the particular or incremental risks attached to innovative and non-conventional investments? Do these warrant special recognition by NRAs? To which extent, if any, is this incremental risk borne by DSOs?

There can be a further disincentive to DSOs to invest in smart grid developments. As smart grids are generally less-capital intensive than conventional assets, DSOs might prefer to invest in assets that add to their regulatory asset base (RAB). This preference might be heightened in regulatory approaches where most CAPEX are passed through, while only some OPEX are. Moreover, this financial preference may be further backed by cultural preferences in DSOs to tend to favour more traditional investments.

For example, in recognition that smart grids investment may increase the weight of operational expenditure (OPEX) in total expenditure (OPEX and CAPEX), whereas the CAPEX may decrease its weight, some NRAs have moved towards approaches based on total expenditures, which does not treat cost categories (OPEX and CAPEX) differently. This choice has the advantage of a DSO being incentivised to reduce total costs in the way a DSO considers it most efficient to do so, rather than strongly focussing on one of the two, based on the regulation by NRAs.

Under a traditional, CAPEX/OPEX approach, the regulator defines CAPEX, based on accounting procedures or on a specific regulatory approach. Companies are allowed to add any expenditure on these items to their RAB. Companies earn a rate of return (to reflect the cost of borrowing) on that expenditure over a number of years (for instance, 20 years). Any expenditure not falling into the CAPEX definition is treated as operating expenditure (OPEX) on which no rate of return is paid[24]. The company is allowed to recover OPEX from customers over a shorter time period.

There are a number of ways in which NRAs can implement a total expenditure approach. For example:

- Some NRAs simply define a TOTEX approach as a system which does not treat cost categories (OPEX and CAPEX) differently. The system usually accounts for an adequate rate of return on a regulated asset base (RAB) and depreciation (the sum of both accounting for CAPEX and OPEX). A regulatory formula is then applied on the total sum of the components (and not just on one of the sub-items). Such a system avoids costs that can be shifted between the CAPEX and OPEX blocks.

[23] Cost overruns, time overruns, stranded assets, identification of efficiently incurred costs, liquidity.

[24] In most countries, an efficiency regime is applied to OPEX via productivity targets (X-factor in price-cap formula).

- Other NRAs define a split of total expenditure between OPEX and CAPEX. All expenditure is then treated as TOTEX, with a fixed percentage being added to the RAB to earn a return and a fixed percentage being treated as operational expenditure. This removes any incentive on companies to have a bias towards capital investments, since they are guaranteed to earn a rate of return on a proportion of all expenditure;

Other approaches can be considered to explicitly promote smart grids, for instance: i) increasing the length of the regulatory period between each price review, ii) adding a premium to the rate of return applied to smart grid investments, iii) moving toward an output based regulation, iv) a mix of these regulatory approaches framed by a long term regulatory commitment to promote smart grid investments.

Consultation question:

13. Does the conventional focus on rate of return regulation on capital expenditure, and in some cases limited pass through of OPEX, have the effect of discouraging certain smart grid investments? What alternative approaches help incentivise DSOs to adopt smart grids?

It is important to think through the full impact of DSOs investing in innovation activities. This innovation will potentially impact the whole electricity value chain and will result in new activities and new relationships being developed between stakeholders. This could mean that the DSO is not involved in, or even is not aware of, technical and operational innovations being developed elsewhere in the market place by stakeholders. This, in turn, could result in duplication or unnecessary investments taking place. DSOs should be incentivised to work in partnership with others on innovative ideas that benefit the network and facilitate markets where appropriate. We also recognise that the nature of innovation is that some initiatives may fail, and it is important that learning is shared to benefit future initiatives. The overall impact of any support to DSO explicit investments has to be balanced in order not to distort or “crowd out” competitive activities that depend on the grid but are beyond the scope of operators’ remit. For instance, it may be important to assess whether it is still necessary to incentivise investment when demand in itself justifies the need for innovative investment.

Incentives can be input based or output based. Under an input based approach, the NRA calls for project proposals and selects the best of the proposals according to cost benefit analysis. It then allows the DSO remuneration through price control allowance or tariffs for the selected projects. Output based incentives are where the NRA sets upfront targets for the DSO to meet (such as quality of service, or minimum technical requirements). The DSO can then either earn a financial reward if it beats these targets, or be subject to financial penalties if it fails to meet them.

One of the recommendations in the CEER/ERGEG smart grids conclusions paper[25] and “The Bridge to 2025” conclusions is to develop guidelines for good practice on incentives schemes (including, but not limited to output-based schemes). This can allow DSOs to weigh up the risks and rewards of new investments. For instance, deciding if they want to invest more in R&D to use the learning to beat outputs in the future and earn financial rewards.

[25] ERGEG Position paper on Smart Grids, Ref: E10-EQS-38-05

The main aspects of output based regulation are as follows:

- **Material:** the outputs should make a significant contribution toward the objectives of sustainable network regulation; the valuation of output is established, possibly reflecting the value for the customer or for society (positive externalities);
- **Controllable:** the network company should have a degree of control over performance against the outputs, with the strength of any incentive taking account of the degree of controllability;
- **Measurable:** it should be possible to meaningfully measure the outputs using quantitative or qualitative methods. Key outcome indicators are identified (measurement methods may need to take account of effects caused by activity that the DSO does not have control over) and authoritative and enforceable guidance for data recording and auditing is issued by the regulator;
- **Comparable:** it should be possible to measure the outputs meaningfully over time and across network companies in a sector by normalising the levels of performance that they are incentivised to achieve;
- **Applicable:** it should be possible to use the outputs to set penalties and rewards as part of the process of determining revenue allowances;
- **Enforceable:** outputs should be enforceable and there should be financial penalties for failure to deliver.

Annex 5 to this consultation provides some examples of output based incentive regimes either already in place or being developed by NRAs.

Consultation question:

14. CEER would welcome views from stakeholders on the pros and cons of output based incentives. Please also define for which regulatory incentives they might be appropriate.

3.2 Demand-side response: an alternative to grid development?

One of the tools which DSOs can use to help deliver price control outputs more efficiently is demand-side response (DSR)[26]. It is important that any DSO role should not have the effect of foreclosing the market for DSR. As stated in Chapter 1, there must be a special justification to allow DSOs to play an active role in this regard.

DSR can play an important role in releasing system wide benefits (as a result of reducing the costs of decarbonisation) for wholesale markets, networks and ultimately consumers. While DSO costs generally comprise less than 30% of the current customer bill, this proportion may increase as DSOs are asked to connect or accommodate more renewable generation,

[26] DSR means a change in the pattern of demand or generation in response to a stimulus such as a tariff or as part of an automated response the customer has agreed to provide. DSR can take a number of forms and we have set out some illustrative examples in Annex 6.

electric vehicle charging points or heat pumps, which may require grid reinforcement[27]. DSR has the potential to reduce these costs along with the time and disruption required to connect these technologies.

However, DSO tariffs or commercial arrangements designed to procure DSR must not add undue complexity to the retail market. Suppliers may need to develop more complex billing systems to process distribution tariffs and care must be taken to ensure that consumers can understand more complex choices, both in terms of billing and consumer choice. There is also a potential risk that DSOs 'corner the market' for DSR at the point of connection and deny, or at least frustrate, other parties gaining access to it. NRAs may need to place boundaries on the role of the DSO in procuring DSR alongside effective controls and/or requirements for transparency of arrangements to avoid such issues.

The success of DSR in reducing energy and network costs will depend on consumers being willing to change their pattern of demand or generation in exchange for a financial payment. This payment should take account of wider system benefits resulting from the response, allowing for appropriate redistribution among all parties involved.

The other aspect which will be crucial to the success of DSR is for consumers to be presented with a proposition which can be clearly understood and relates to their use of energy. The automation of equipment at consumers' premises can help them provide DSR (and reduce their energy bills) while allowing them to go about their lives as usual. Such automation may require the installation of equipment at the customer's premises. CEER sees this primarily as a contractual matter between the consumers and the energy service provider (either supplier or ESCo or aggregator).

3.3 Structure of DSO tariff (capacity vs. consumption)

Consumption of electricity by some customers is falling. This is due to a variety of reasons – improved energy efficiency, increased levels of self-consumption, the impact of the economic crisis, etc. Where DSO electricity tariffs are primarily recovered through a consumption charge (€ per kWh), DSOs are concerned that they will be unable to recover the allowed revenues set by regulators. DSOs are also concerned that the consumption charge may be disproportionately high (in comparison to the capacity element).

Network costs are mainly capacity driven. A majority of Member States use consumption (volume) based tariffs to allow DSOs to recover at least 50% of the allowed DSO revenues[28]. A future DSO tariff structure may be used to encourage customers to reduce consumption at peak times (including using their own generation).

[27] For example, a study in GB illustrated that DSR and smart grid solutions could reduce the cost of meeting the UK Government's carbon targets from £24bn down to closer to £13bn out to 2050. Full report available: https://www.ofgem.gov.uk/ofgem-publications/56824/ws3-ph2-report.pdf

[28] 'Network tariff structure for a smart energy system', EURELECTRIC, May 2013.

Table 1 below provides some illustrative examples of DSO electricity tariffs which could be used to influence consumption patterns. It assesses the strength of the economic signal sent to customers to encourage them to manage their demand and also the level of certainty for revenue recovery it provides to the DSO. The table indicates that certain tariff structures are more beneficial in that they provide a strong economic signal to the customer. However, on the other hand these tariff structures may increase the risk to the recovery of costs by the DSO. CEER will need to give further consideration to the appropriate regulatory treatment of such tariffs.[29]

Illustrative example tariff	Description	Strength of economic signal to consumers	Certainty of recovery for DSOs
Flat rate capacity charge	A fixed € per kVA or kW charge based of capacity a customer uses.	**Medium**	**High**
Flat rate consumption charge	A € per kWh flat rate charge	**Medium**	**High**
Consumption based time of use tariff	A variable € per kWh charge which could include a higher price during network peak time	**High**	**Medium**
Capacity based time of use tariff	A variable € per kVA or kW charge which would include a higher price during network peak time	**High**	**Medium**

Table 1 - Examples of tariff structures

Table 1 illustrates that both capacity and consumption based tariffs can be structured to provide an incentive on customers to manage their usage at peak times. A time of use tariff based on either capacity of consumption can send an economic signal to customers to manage their on-going usage.

The table also highlights that wherever DSO tariffs are set based on assumptions about customer behaviour (consumption or capacity used) there is a risk of over or under recovery of DSO revenues. DSOs should not be fully exposed to this risk but should be incentivised to manage this risk appropriately. As customers' consumption patterns change, there needs to be some opportunity to ensure that the basis for setting DSO tariffs can be updated regularly or that the tariff structures themselves are flexible enough to take account of this.

[29] An alternative way, used by a growing number of NRAs, is to have an ex-post reconciliation mechanism (also called "regulatory accounts") that makes the DSO neutral to the assumptions made about future demand evolution. With the use of such "regulatory accounts", differences between the calculated and actually received revenues are considered cost-reducing or increasing in a future cost setting period (often after a t-2 delay). This works for both positive and negative balances.

Consultation question:

15. Do you agree that to allow timely recover of DSO revenues, assumptions on consumption patterns in tariff models could be updated within price control periods?

3.4 Time-of-use distribution network tariffs (via supplier)

Distribution tariffs try to strike a careful balance between a number of factors such as cost reflectivity against simplicity and predictability in order to facilitate retail competition[30]. Some of these principles are established in the Electricity Directive (Directive 2009/72/EC).

The Energy Efficiency Directive (Directive 2012/27/EC) specifies some further criteria for energy network regulation and grid tariffs. It states that NRAs should ensure that network tariffs and regulations incentivise improvements in energy efficiency and may support dynamic pricing for demand response measures by final customers. Regulators will need to consider if and how to introduce Time of Use (ToU) network tariffs in a simple and effective manner. Coordinating such network tariffs with system hourly prices in the energy market may be a very difficult task, as while there will be some co-incidence between the two, ToU network tariffs will be developed to reflect local conditions, while ToU energy prices are determined at a system level.

In Member States where the regulator sets only allowed revenues, but where the DSO can design distribution tariffs applied to its network users, the DSO or the regulator might decide to introduce a new ToU distribution tariff. This tariff could reflect the times when it was more expensive to use the DSO network. In all circumstances, this tariff would be billed to the supplier who must then decide how it reflects this in the end bill to the customer. Annex 6 provides a description of static and dynamic time of use tariffs. Time of use tariffs have proven to be effective in reducing peak demand. Dynamic tariffs, such as critical peak pricing, critical peak rebate or real-time pricing, may lead to an even higher reduction in peak consumption.

In a competitive retail market, one might expect the distribution tariff, whether static or dynamic, to be passed through by the supplier to the end consumer. However, NRAs may justify an explicit requirement to pass through the price signal in a distribution tariff to the end consumer on the basis that the tariff is aimed at delivering or promoting a change in consumer behaviour. Where this is the case, it may be up to the NRA to decide whether the supplier is restricted from offering tariffs which do not pass though the distribution dynamic tariff (either in part or in full) or whether the supplier should only offer tariffs to the end user which reflect the distribution dynamic tariff. Where this occurs, NRAs should justify this approach and take account of any potential impacts on competition amongst suppliers.

[30] Other factors include; certainty of revenue for DSOs, cost reflectivity to promote efficient use of the network by users; non-discrimination and help to promote competition in supply and generation.

Consultation question:

16. How can ToU network tariffs be coordinated with system energy prices?

17. Are there circumstances under which suppliers should be required to pass through the distribution tariff signal to customers? If so, should there be regulation to ensure this happens?

3.5 Contractual arrangements

In the conclusions of CEER's "Advice on *Ensuring Market and Regulatory Arrangements help deliver Demand-Side Flexibility*"[31], CEER recognised that the roles and responsibilities of all involved actors (market participants, DSOs, TSOs etc.) should be clarified to be consistent with a level playing field and announced that the forthcoming CEER consultation paper on Role of the DSO (i.e. this paper) would examine this issue.

In this section, we apply the principles and the framework from Chapter 1 to DSR contracts where DSOs are involved. We seek stakeholders' view on this rather open and innovative point.

Contractual DSR relationships for a DSO

From a DSO perspective, we distinguish four types of DSR contractual relationships:

1. DSOs will already have a direct relationship with customers to undertake connection works. The legal basis for this is usually a **connection agreement between the DSO and the customer**. This can be the traditional or existing agreement, but it can also be a new agreement or a modification of the existing one (for instance, when the customer must increase the rated power because he/she needs to recharge electric vehicles).
   It seems reasonable that DSOs should be able to procure DSR from these customers via the connection agreement, particularly if it helps reduce the connection cost or time to connect for the customer[32]. This rationale may equally apply to domestic customers connecting new low carbon and flexible appliances in the home (e.g. electric vehicles). This is predicted to be a key driver of DSO costs and entering into a DSR arrangement with the DSO at the time of connection could reduce these costs, vis-à-vis non-firmness of the connection. The use of the connection agreement for contracting DSR directly with customers must be balanced with the customer-centric approach, notably in respect of smaller consumers.

[31] Ref. C14-SDE-40-03, 26 June 2014

[32] This charge will vary depending on the connection boundary in Member States. In some Member States, a super shallow connection is applied, and therefore the connecting customer makes no or very small contribution to reinforcement costs. Others MSs have a shallowish approach, where the connecting customer pays a share and the wider customer base pays a share. Some Member States have a deep connection regime whereby the connecting customer picks up all the costs of reinforcing the network to meet their capacity requirements.

2. When thinking about how DSO tariffs could evolve to facilitate DSR, we also need to consider **commercial arrangements**. Procurement of DSR can be driven by a range of issues (e.g system issues) and so the DSO should be able to respond to these system issues through appropriate DSR procurement initiatives in the market place.

   We have made a distiction between existing domestic customers (who are unlikely to know who their DSO is) and larger commercial customers and generators who may already have a technical agreement with the DSO. It may be more appropriate for the latter to have additional commercial agreements with the DSO (subject to appropriate regulatory oversight and provided that adequate separation is ensured: this is the case, for instance, where DSOs do not carry out data management activities). Care must be taken so that the domestic customers are not confused by such offers, as this could impact how they engage in retail markets. This ensures consistency with the 'consumer centric' model.

   According to Principle 1[33], the contract is between the final customer and the supplier/aggregator, who acts as main point of contact. Furthermore, according to Principle 2, all contractual arrangements that deviate from this standard contract must be subject to regulatory control in terms of both technical conditions and prices offered to customers. If new contractual arrangements are introduced, all customers should hence be allowed to choose from the same menu of options without undue discrimination or arbitrary behaviour by the DSO.

3. The DSO should be free to **contract with an aggregator** to procure DSR from existing customers.

4. The DSO should be free to **contract with a supplier** to procure DSR from existing customers.

Types of DSR contracts

For an overview of potential DSR contracts we refer to the THINK Report[34] that describes the following types of DSR contracts (see also Annex 6):

a. **Static based contracts ('*Static Time of Use*')** that have predefined fixed tariffs for predefined time intervals. The contracts are simple to understand and some savings can be made by customers by consuming less in the more expensive time intervals.

b. **Dynamic price-based contracts ('*Dynamic Pricing*')** that set tariffs at short term notice for certain time intervals. The contracts are more complex and financial risks and benefits can be high(er) depending on the ability of customers to respond to the short term price fluctuations.

[33] See chapter 1, paragraph 1.1 of this document.

[34] THINK, *Shift, Not Drift: Towards Active Demand Response and Beyond*, Topic 11 Final Report, June 2013 (ISBN 978-92-9084-141-8).

c. **Static volume-based contracts (‘*Fixed load capping*’)** that predefine tariffs and time intervals with volume caps or floors. The complexity in this type of contract is that the customer cannot exceed a certain cap e.g. needs to accept load limitations.

d. **Dynamic volume-based contracts (‘*Dynamic load capping*’)** that usually have fixed caps with short term price notices. These contracts are complex due to frequent load cap changes.

e. **Direct load control contracts (‘*Direct load control*’)** where a third party controls a part of the electricity consumption of the customer. Automatic and remote shifting or curtailment of specific customer’s appliances (or even the entire connection) is agreed, where the customer may set certain parameters.

A regulatory view on DSR contracts for DSOs.

CEER has taken notice of the many types of DSR contracts and the wide range of benefits, risks, objectives, situations and players that can have impact on DSR-solutions. Because of the many different forms of DSR contracts and situations, it is not possible to describe regulatory details for each contract or for each situation. However, CEER considers the framework and the principles as described in Chapter 1 as the fundamentals for the regulatory framework for DSR contracts for DSOs.

Below we give a preliminary indication of a potential regulatory view (drawing from the 3 categories of allowed DSO activities, see Page 12) on the contractual relationships for each type of DSR contracts described above and according to the specific customer category involved (domestic, commercial/industrial, distributed generator).

	1.Connection Agreement DSO-Customer			2. Additional and commercial DSR contract DSO-Customer			3. Additional and commercial DSR contract with customer via aggregator	4. Additional and commercial DSR contract with customer via supplier
	Domestic Customer	Commercial and Industrial Customer	Distributed Generation Customer	Domestic Customer	Commer-cial and Industrial Customer	Distributed Generation Customer		
a. Static Time of Use	I	I or II	I	III* or IV	III	III	III	III
b. Dynamic pricing	III	I or II	III	III* or IV	III	III	III	III
c. Fixed load capping	III or IV	I or II	III	III* or IV	III* or IV	III	III	III
d. Dynamic load capping	III or IV	I or II	III	III* or IV	III* or IV	III	III	III
e. Direct load control	III or IV	I or II	III	III* or IV	III* or IV	III	III	III

** Only in Member States where DSOs do not carry out data management activities.*

Table 2 Regulatory views on possible contractual arrangements, according to the activity categories in Chapter 1

Notwithstanding the above, it is important to notethat we do not yet know how the markets will develop and that, in order to unlock the value of demand-side response, a regulatory framework is required that is flexible enough to adapt in an evolving market. As stated in this consultation paper, there is no one-size-fits-all solution; the ultimate reason for the complexity of the above table is that the role of the DSO in flexibility must be designed consistently with many other aspects.

Consultation questions*:*

18. Do you agree with the above assessment (in Table 2) of different cases when DSOs or other parties should have contracts or agreements with consumers and distributed generators?

19. Which type of regulatory controls should be adopted by NRAs for DSOs, in cases of contractual arrangements falling under categories II and III?

4 Next steps

CEER invites all interested stakeholders to respond to this public consultation via the dedicated online tool. The deadline for responses in **27 February 2015**.

Following the 8+ week consultation period, CEER will consider responses to this consultation carefully and prepare an evaluation of responses. We are also planning to hold a workshop with stakeholders to discuss key issues in each of the three areas covered by this consultation – the activities of the DSO, the DSO-TSO relationship, and incentives and charges. We will then publish a final report and take forward further actions in the CEER work programme for 2015. These actions include a roadmap on regulatory initiatives relating to DSOs to implement the conclusions of our report.

Annex 1 – CEER

The Council of European Energy Regulators (CEER) is the voice of Europe's national regulators of electricity and gas at EU and international level. Through CEER, a not-for-profit association, the national regulators cooperate and exchange best practice within and beyond Europe's borders. CEER includes national regulatory authorities from 33 European countries (the EU-28, Iceland, Norway, Switzerland, FYROM, Montenegro and growing).

One of CEER's key objectives is to facilitate the creation of a single, competitive, efficient and sustainable EU internal energy market that works in the public interest. More specifically, CEER is committed to placing consumers at the core of EU energy policy. CEER believes that a competitive and secure EU single energy market is not a goal in itself, but should deliver benefits for energy consumers.

CEER works closely with (and supports) the Agency for the Cooperation of Energy Regulators (ACER). ACER, which has its seat in Ljubljana, is an EU Agency with its own staff and resources. CEER, based in Brussels, deals with many complementary (and not overlapping) issues to ACER's work such as international issues, smart grids, sustainability and customer issues. European energy regulators are committed to a complementary approach to energy regulation in Europe, with the Agency primarily focusing on its statutory tasks related to EU cross-border market development and oversight, with CEER pursuing several broader issues, including international and customer policies.

The work of CEER is structured according to a number of working groups and task forces, composed of staff members of the national energy regulatory authorities, and supported by the CEER Secretariat.

This report was prepared by the CEER DSO Working Group.

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Annex 2 – List of abbreviations

Term	Definition
ACER	Agency for Cooperation of Energy Regulators
AFID	Alternative Fuels Infrastructure Directive
CAPEX	Capital Expenditure
CEER	Council of European Energy Regulators
DER	Distributed Energy Resource
DG	Distributed Generation
DSO	Distribution System Operator
DSR	Demand-side response
ESCO	Energy Service Company
EV	Electric Vehicle
GGP	Guidelines of Good Practice
HV	High Voltage
IEM	Internal Energy Market
LV	Low Voltage
MV	Medium Voltage
NC	Network Code
NGV	Natural Gas Vehicle
NRA	National Regulatory Authority
OPEX	Operational Expenditure
PV	PhotoVoltaic
RES	Renewable Energy Source
RIIO	Revenue = Incentives + Innovation + Outputs
RPT	Reverse Power Flow Time
SME	Small-Medium Enterprise
TLC	Telecommunication
TOTEX	Total Expenditure
ToU	Time of Use
TSO	Transmission System Operator
VIU	Vertically Integrated Undertakings

Annex 3 – List of questions for consultation

Chapter 1:

1. *Do you agree with these three core principles?*
2. *What challenges would new forms of stakeholders (e.g. community or municipal energy schemes and ESCOs) bring to DSOs and to existing approaches?*
3. *Do you agree with the proposed logical framework? Are there other important questions which should be included in the framework?*
4. *Do you agree with the proposed assessment of activities and are there any additional grey areas for DSOs other than those considered?*
5. *For activities falling in category II and III (see Figure 1), under which regulatory conditions could DSO intervention be allowed?*
6. *Do you agree with the assessment of DSO access to data and data management?*
7. *Do you agree that the risk of DSOs participating in some of the 'grey areas' (particularly flexibility and DSR) decreases the more separated a DSO's operational activities are from other competitive activities carried out by other companies within the same vertically integrated group?*
8. *Do you agree with first considerations on the* de-minimis *threshold?*

Chapter 2:

9. *Do you consider all the activities and topics described in this Chapter relevant to further defining a regulatory framework for DSO-TSO relationship and responsibilities? Are any activities or topics missing in the DSO-TSO relationship discussion?*
10. *Do you agree with the description of the activities and topics in this Chapter? If not, what is your view on your specific activity or topic that is relevant for the DSO-TSO relationship?*
11. *Do you agree with the statement that further regulatory guidelines may be required (in addition to current Network Codes) and if so, which regulatory guidelines do you consider necessary?*

Chapter 3,

12. *What, if any, are the particular or incremental risks attached to innovative and non-conventional investments? Do these warrant special recognition by NRAs? To which extent, if any, is this incremental risk borne by DSOs?*
13. *Does the conventional focus on rate of return regulation on capital expenditure, and in some cases limited pass through of OPEX, have the effect of discouraging certain smart grid investments? What alternative approaches help incentivise DSOs to adopt smart grids?*
14. *CEER would welcome views from stakeholders on the pros and cons of output based incentives. Please also define for which regulatory incentives they might be appropriate.*
15. *Do you agree that to allow timely recover of DSO revenues, assumptions on consumption patterns in tariff models could be updated within price control periods?*
16. *How can ToU network tariffs be coordinated with system energy prices?*
17. *Are there circumstances under which suppliers should be required to pass through the distribution tariff signal to customers? - If so, should there be regulation to ensure this happens?*
18. *Do you agree with the above assessment (in Table 2) of different cases when DSOs or other parties should have contracts or agreements with consumers and distributed generators?*

19. *Which type of regulatory controls should be adopted by NRAs for DSOs, in cases of contractual arrangements falling under categories II and III?*

Annex 4 – Table of potential DSO activities

Activity #	Activity Description	Future Category* I	Future Category* II / III / IV	Future Category* V
A	***Existing and evolving core activities***			
A1	Activities related to the (efficient) energy network infrastructure	X		
A2	System security	X		
A3	Gas quality checks	X		
A4	Technical data management	X		
A5	Managing network losses	X		
B	***Activities where DSOs should not be involved***			
B1	Energy generation			X
B2	Energy supply			X
B3	Exception to allow contracting local temporary generation for the sake of continuity of supply		X	
B4	Exception on reaching beyond the meter for gas safety issues		X	
B5	Exception to allow supplying energy as supplier of last resort		X	
C	***Activities related to retail liberalisation***			
C1	Relationships with retail suppliers	X		
C2	Activities in respect of final customers for revenue protection		X	
C3	Activities performed by DSOs on supplier's request, including customer switching		X	
C4	Activities for commercial data handling		X	
D	***Activities related to renewables penetration and new flexibility needs***			
D1	Local dispatching for local resources		X	
D2	Energy storage		X	
E	***Activities related to infrastructure provision for electric/gas vehicles***			
E1	Operate non-discriminatorily towards any other person who owns and operates EV recharge infrastructure	X		
E2	Development of EV recharge as well as NGV fuelling infrastructure		X	
F	***Ownership & management of meter***			
F1	Owning and managing the metering equipment	X		
F2	Market driven approach, where metering activities are carried out by separate, independent meter operators			X
G	***Activities related to energy efficiency***			
G1	Improving energy efficiency of the network	X		
G2	Activities reaching beyond the meter (e.g. into customers' homes etc.).			X
G3	Providing advanced devices and added-value services for energy efficiency		X	
H	***Other activities out of the electricity/gas supply chain***			
H1	Offering services to telecom companies		X	
H2	Other public electricity-related services like public lighting, traffic light operations, etc.		X	
H3	Other energy-related services like district heating, etc.		X	
H4	Sharing smart metering infrastructure		X	
I	***Data Handling***			
I.1	Customer data management		X	
I.2	Data collection for system security	X		

** As more research on each activity is needed for allocation to categories II, III and IV, in the current allocation these categories are merged.*

Categories of DSO activities:

I. Core activity
II. Allowed under conditions (no potential competition)
III. Allowed under conditions (potential competition, but special reason justifyung DSO participation)
IV. Activity not allowed (potential competition and no special reason justifying DSO participation)
V. Activity forbidden

Annex 5 – illustrative examples of output based incentives

GB (Ofgem)

In 2010, Ofgem introduced a new approach to price controls which is output-based. The framework is named RIIO (Revenue = Incentives + Innovation + Outputs). It contains 5 core output categories; reliability & safety; connections; customer satisfaction; social obligations; and environment. Companies conduct stakeholder engagement to assess what its customers want to see in terms of outputs in these categories. They use this to help develop an 8-year business plans. The business plan should strike a balance between the outputs customers want and their willingness to pay.

These business plans are assessed by Ofgem who assess whether the plan delivers good value for money to customers. If it does, then Ofgem can 'fast track' the plan and it is agreed without further scrutiny. Those plans not 'fast tracked' must be resubmitted by the company. Ofgem then assesses these revised plans in greater detail and can adjust the costs or outputs proposed.

Once all business plans have been accepted, companies report annually on performance against the set outputs and expenditure. Where companies beat their outputs, they can earn a reward (per unit). Where companies fail to meet their outputs, they will face a penalty. These rewards or penalties automatically feed into the revenue which DSOs can recover.

In addition, the RIIO framework includes an efficiency incentive. This shares any overspend or underspend against the price control allowance with customers. For instance, for every £1 which a company saves against its allowance, its shareholders will keep around 60p and customers will be returned the remaining 40p. The opposite is true for any overspend. This provides a strong incentive for DSOs to make efficiency gains on top of those set in the price control.

Sweden (EI)

The Energy Markets Inspectorate (Ei) is introducing output-based incentives, encouraging a more efficient utilisation of the electricity network. The regulation is based on two incentives: one to reduce power loss in the network and one to even out the usage of the network (load shift).

The following is the method for calculation of the incentive for power losses:

$$Kn = (Nfbaseline - Nfoutcome) \times E \times Pn \times 0{,}5$$

The difference between the indicator (Nf) for the baseline period and the indicator for the regulated period is multiplied by volume energy passing through the system, the regulated period (E) multiplied by energy price (Pn) and multiplied by 0,5. The energy price is the average price for all network operators during the regulated period. The number 0,5 represents the sharing of the incentives between network companies and customers.

The following is the method for calculation of the incentive for load mitigation:

$$Kb = Lf \times Bdiff \times E$$

A load shift in the network should result in a lower cost for the feeding grid when the network operator could lower their subscribed maximum power. Bdiff represents the cost saving for the feeding grid per energy unit (comparing baseline period and the regulated period). This is multiplied by the volume energy passing through the system, the regulated period (E) and the load factor (Lf). In order to receive the incentive, the network operator must fulfil one criterion, which is to decrease their cost for the feeding grid per energy unit. The cost-saving is shared between the costumers and the network operator (profit-sharing) based on the load factor. A theoretical load factor of 1 would allow the network operator to keep all of the earned savings.

Finland (EV)

In Finland, EV has used output-based smart meter incentive since 2012 to ensure effective roll-out and operability of the meters. The incentive allows operative roll-out costs (€5 per site up to 63 amps) and a capital cost of a smart meter to be included in the regulated asset base if and only if smart meters are providing hourly read data to consumers and suppliers. Also, the energy balance settlement has to be done by using the data from smart meters. The total operative costs of the incentive to the consumers were €6 million, but the due the output requirement, the DSOs allowed capital costs declined €13 million in 2012. Since the beginning of 2014, more than 90 percent of the consumers are served by smart meter and data from the meters is being used as designed in the incentive.

Italy (AEEGSI)

In Italy, a transition from input-based to output-based incentives is under consideration. Demonstration projects for smart grids on small local scale have been incentivised in order to test in field a couple of concepts: Psmart, an indicator of Hosting Capacity that gives the increase in DG-production that can be connected to a given distribution grid in safe operational conditions (as for voltages, currents and frequency) without infrastructural expansions; and Reverse Power Flow Time (RPT), an indicator that gives the number of hours, in the year, during which power flow from MV to HV is observed at the interface with transmission grid.

The basic idea is that output-based incentives are much more efficient than input-based ones, because DSOs have to find the less expensive solution given the output metrics, including some technical requirements, the ex-ante output valuation and the priority addresses. According to the Italian regulator, the new output-based incentives have to be bilateral, i.e. DSOs will be exposed to both rewards (possibly linked hosting capacity) and penalties (that could be related to curtailment of distributed energy, excluding emergency conditions requested by TSO for system balancing). In order to define a clear and effective output metrics, the regulator is keen to extract lessons from pilot demonstration projects. In particular, a number of technical requirements, that smart investments have to fulfill to get incentives, are to be defined. Requirements should define a list of minimum "smart functionalities" that smart grids have to ensure. As a filter for priority, RPT indicator proved to be very effective and simple and is likely to be used to identify distribution grids with most merit for output-based incentives. Last, solutions must be found in order to minimise costs for connectivity: under this respect, involvement of network users and market-driven, non-proprietary solutions are the key, as well as coordination between energy and telecom regulator.

Portugal (ERSE)

The Portuguese methodology was presented to the stakeholders in 2011, as part of a set of regulatory schemes for the next regulatory period. The regulatory period began in 2012. The Portuguese regulation brings together two main features: i) innovative investments benefiting from a “premium” of 1.5% on their remuneration; ii) output target: OPEX efficiency target rises with the declared penetration of innovative investments for the regulatory period. Where the innovative investment is lower than previously declared, the DSO would be penalised. This approach tried to be neutral for the consumers in terms of risk, since the greater rate of return has a counterpart: a greater efficiency obligation applied to the OPEX that is equivalent in terms of returns for the company to the greater return in CAPEX. However, if the company was more efficient than the efficiency target due to its investments in smart grid or where it invested more than foreseen, it can keep all the extra returns. Currently, the major issues that have to be tackled in the current regulatory review for the next regulatory period, 2015-2017, are: i) Making the regulatory scheme more appealing for the DSO to invest in innovative investment, diminishing its risk; ii) Making it more output oriented, linking it to other targets, for instance quality of service and losses.

The Portuguese regulator is approving some changes to the regulatory incentive, to reflect the experience of the first 3 years of the mechanism. These will include ex-post adjustment to the incentive to match the actual innovative investment made by the DSO and a set of criteria to classify innovative projects as eligible, considering their positive social externalities.

Annex 6 – illustrative examples of DSR arrangements

The following list is not intended to be exhaustive but provides examples of how demand-side response (DSR) arrangements could work. The description of DSR products is drawn from the THINK Report "Shift, not drift".

Type of DSR	Description and characteristics
Static price-based contract: **TOU pricing contract**	• This contract fixes tariffs for different intervals (e.g. 8.00h-22.00h day-tariff and 22.00h-8.00h night tariff), typically predefined upfront at the start of the contract; • Passes on some price risk to the consumer, but includes no volume risk • Simple to understand; • The consumer remains in total control over his consumption without having to compromise in terms of privacy; • The financial compensation to be expected for this contract is limited and indirect through the savings made by consuming less in the more expensive intervals.
Dynamic price-based contract: **Dynamic pricing contract**	• This contract fixes hourly tariffs with day-ahead or hour-ahead notice, typically reflecting wholesale price variations; • Passes on much price risk, but has no volume risk; • More demanding in terms of complexity as the signal changes frequently, requiring minimum levels of automation • The consumer remains in total control of his consumption and the related personal information; • The consumer might expect a higher financial compensation, but due to the price risk the final compensation will depend on his performance to consume less when prices are high
Static volume-based contract: **Fixed load capping contract**	• This contract fixes load caps and/or floors for different intervals (e.g. 8.00h-22.00h day-tariff and 22.00h-8.00h night-tariff). Both the intervals and prices are predefined upfront at the start of the contract; • Passes on a limited amount of volume risk, but does not include price risk; • Complexity is high because the consumer has to learn how to use his appliances to meet the contractual floors and caps; • The consumer loses some autonomy/privacy because of the load constraints: e.g. having to disclose when cap can be low or must be high; • The financial compensation to be expected from this contract is limited.
Dynamic volume-based contract: **Dynamic load capping contract**	• This contract fixes hourly load caps/floors with day-ahead or hour-ahead notice, possibly reflecting wholesale market conditions. But the prices are typically predefined. • Passes on high volume risk, but no price risk; • High complexity of adapting load frequently, requiring minimum levels of automation;

	• The consumer will have to reveal more information about the timing of his consumption and is possibly restricted in what he can consume (e.g. the power cap could preclude simultaneous cooking and washing), implying a loss of autonomy/privacy; • The consumer might expect a higher financial compensation. We further distinguish a c*ontrol-based* contract in which the consumer cedes the control over specific appliances to the counterparty in the contract. The consumers are therefore not expected to react to any signals themselves.
Dynamic volume-based contract: **Dynamic load capping contract**	• According to this contract, a clearly identified part of the consumer's electricity consumption is effectively placed under the control of a third party. This third party then automatically and remotely shuts down, starts up or cycles electric appliances at the consumer's premises; direct load control contract is an incomplete contract that can be complemented by another contract type for the part of the load not subject to direct control; • There is no price and no volume risk for the consumer; • The consumer loses all autonomy and will have to disclose personal information regarding which appliances can be used when by the third-party for establishing the contract; • The financial compensation can be limited or high depending on the size of the load subject to third-party control.