Study on tariff design for distribution systems

Final Report

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1. Executive summary and main results

This report presents the results of the Study on Tariff Design for Distribution Systems commissioned by DG Energy to the consortium of AF-Mercados, REF-E and Indra.

The objective of the project is collecting information about regulatory schemes applied in the Member States to electricity and gas distribution, identifying best practices and developing recommendation for the Commission on desirable features of distribution tariff regulation, in the light of the foreseeable changes in the distribution business.

In particular, the consortium's mandate included the following pieces of work. First, the consortium was required to develop a set of indicators allowing to compare multiple aspects of gas and electricity distribution businesses across Member States, with the ultimate purpose of assessing cost-effectiveness, quality of service and operational efficiency. We have developed indicators of: products and services supplied by the distributors, quality of service, network topology and cost. We refer the interested reader to Section 2 of the report for the presentation of these indicators.

Second, we were required to review and discuss principles driving the design of effective tariff regulation schemes. We grouped these principles under three headings: system sustainability, which refers to the ability of the regulatory system to attract capital in the industry; economic efficiency, which refers to the ability of the regulatory system to induce cost minimization in the short and in the long term; protection, which refers to the achievement of a fair split of the surplus generated in the industry among the stakeholders, including in particular regulated firms and consumers.

Third, we were required to characterize the regulatory schemes implemented in all Member States, analyse their outcome in terms of tariff structures and levels, identify best practices and develop recommendations for the Commission. To this purpose we administered a questionnaire and a data request to all European national regulators.

While the project focused on methodological issues, we were asked to collect data from regulators on tariff levels for standard consumers and on distribution costs. We would like to stress that assessing the relative merits of regulatory schemes implemented in different countries based on the tariff and cost comparisons presented in this report would be inappropriate, as it was beyond our mandate to perform an empirical analysis of the factors affecting distribution cost and their allocation among consumer types in the Member States. Such factors include, for example, the structure of distribution and transmission networks, the degree of gas penetration, cost allocation methodologies, distributor's responsibilities and composition of the customer base.

In the remaining of this section we highlight the general findings of our analysis, focusing on their policy implications. The existing regulation of electricity and gas distribution tariffs is in most Member States consistent with the traditional features of the distribution business, which we identify as the following:

- Little generation connected to distribution networks and inflexible demand, so that the primary role of distribution consists in transferring a basically unidirectional power from the transmission network to the consumers' premises, trough relatively passive networks;
- Ensuring universal access to the service or a target network coverage, respectively for electricity and gas, and continuity of supply are the main distribution output;

- Technology and network planning methodologies are consolidated, implying limited uncertainty optimal investment decisions and ease of auditing by regulators;
- Very diverse industry structures among Member States, with high fragmentation in some countries.

The traditional features of the distribution business appear to be reflected in the structure and outcomes of regulatory systems currently implemented in most European countries. In particular:

- With the exception of Great Britain, current incentive-based regulatory schemes place little emphasis on characterizing the outputs delivered by the distributor, but for quality of service schemes in some countries;
- Typically distributors are not exposed to volume risk and to the risk that their investment turn out to be less useful than expected when they were decided, for example because of lower than expected demand;
- Revenue setting mechanisms based on benchmarking are implemented in countries where the distribution sector is highly fragmented;
- Regulators and stakeholders are generally less involved in the decision-making process on distribution network development, compared to transmission;
- Traditional tariff structures reflect a situation of limited availability of information on each consumer's responsibility in causing distribution costs and are also affected by affordability and fairness considerations.

As regards the outcome of the traditional regulatory models the analysis of available data on allowed revenues and distribution tariffs shows that:

- Distribution tariff structures by user groups are very different among countries. For example, the share of distribution cost paid by residential users ranges from 33% to 69% for electricity and from 32% to 86% for gas.
- In most countries, the share of distribution revenues from tariff components based on energy is large, resulting in an asymmetry between the structure of distribution costs (mostly fixed) and the way they are charged to consumers;
- In the electricity sector the energy component applied to households is on average 69% of the total network charge. This situation is common in most countries apart from three (The Netherlands, Spain and Sweden) where the energy charge weights between 21% and 0%. In the case of industrial clients the weight of the energy component is still dominant (around 60% for both small and large industrial clients) but there is more variability among countries and the corresponding weight ranges between 13% and 100%;
- In the gas sector the energy component applied to households is on average 74% of the total network charge and in all the countries with available data its weight is higher than fixed components. For large consumers the weight of energy component is lower than for household consumer, while still accounting around 61% on average. As it happens in the electricity sector, in the case of large consumers there is more variability among countries and the corresponding weight of energy components ranges between 15% and 100%;

- Unit distribution costs are variable among countries both for electricity and gas. We stress, however, that distribution cost differences are the result of multiple factors, which the regulatory scheme is just one of and that investigating the causes of such differences was beyond the purpose of this project. Different DSOs are, in fact, required to provide different qualities of service; they serve different loads, accommodate different proportions of distributed generation and do not operate under comparable conditions in terms of, for example, density of population connected, and geographical constraints, with an impact on network design and operations;

- Unit distribution costs in almost all countries fall within the range 20-35 EUR/MWh. The variability in terms of unit cost per connection point is higher than the per MWh and the different relative position of countries confirms the different composition of user typologies, in particular in terms of consumption levels.

- In the gas sector the variability of average cost shows a range between 2.17 EUR/MWh and 14.61 EUR/MWh.

The distribution activity is currently going through major changes, which may affect the structure of optimal regulatory schemes. First, an investment cycle is being spurred by the need to increase the distribution network's capacity to host an expanding fleet of renewable generators. Future investments appear to depart from traditional distribution upgrades in several respects:

- They involve innovative technologies whose cost and performances are more uncertain and on which information asymmetries between regulators and firms might be greater;

- Multiple options to achieve the same results are available, such as deployment of storage capacity or increasing demand response, deploying smart technologies as an alternative to upgrading lines and substations, distributing or centralising network intelligence, developing new telecommunication infrastructures or exploiting existing ones;

- Distribution investment decisions interact with the outcome of decisions in areas beyond the distributors' control, such as renewable production targets or national deployment strategies of IT infrastructures.

Second, the content of the distribution business is enriching, as distributors take on responsibilities related to dispatch of embedded generation and flexible loads, facilitation of retail competition, energy efficiency.

Such changes are affecting the terms of the trade-off between efficiency and protection objectives in distribution tariff regulation. Regulatory frameworks that, in our view, are most effective in the new environment share the following features, which we present next in the form of recommendations.

Recommendation 1: Distributors should not be exposed to risks related to events that are not under their control. This implies, in particular, that distributors should not be exposed to:

- Volume risk given their limited control on power and gas consumption; this is a feature of regulatory schemes already deployed in most Member States either by adjusting the revenue allowance in the following years to offset volume effects or via largely capacity-based tariffs.

- The risk of cost under-recovery in case investments turn out to be ex-post less useful than expected.

Recommendation 2: major distribution network investment decisions should be subject to a structured and open ex-ante scrutiny by stakeholders and regulators. The outcome of such scrutiny would be a thoroughly audited investment strategy which consumers could be safely required to undertake the risk of. We note incidentally that an open and inclusive decision-making process would ease coordination of distribution investment decisions and the outcomes of related decision making streams.

Complex investment approval proceedings may place an unjustified administrative burden on small distributors and, if the distribution sector is highly fragmented, on the regulator; such cost would ultimately be passed on to consumers via distribution tariffs. Streamlined scrutiny processes, possibly boiling down just to transparency requirements, could be envisaged for investment plans meeting certain predefined conditions, set by the regulator for example via benchmarking. However, we are not aware of countries with highly fragmented distribution industries in which extensive ex-ante scrutiny is implemented. The relative merits of alternative mechanisms to govern network development in that context are therefore largely untested.

Recommendation 3: Financial incentives have proved very effective in aligning the distributors' objectives with the regulator's and, ultimately, the consumers on matters such as quality of service and cost minimisation. The following features increase the power or reduce the cost for consumers of incentive-based regulatory schemes:

- Use of all available information on the efficient costs of distributors. In this respect we recommend that the Commission promote regular publication of information and data about technical features, revenue setting methodologies, output targets and allowed revenues set for distributors in all Member States. Cost unbundling of activities for which a large part of costs can be assessed in isolation – such as metering – should be promoted, as this improves the quality of the information which incentive schemes can be based on.
- Focus on outputs: multiple performance dimensions, or outputs, have to be addressed by incentive-based regulatory schemes as distributors acquire increasing responsibilities. Effective financial incentives in this context can be provided via premiums and penalties related to the achievement of pre-determined output targets. Targets should be selected such that they directly impact on the value of the service delivered by the distributor for network users' and, ultimately, consumers. We note incidentally that output based mechanisms can be implemented on top of a baseline tariff and investment scenario approved by the regulator along the lines of Recommendation 2.
- Focus on total cost and long regulatory periods: setting allowed revenues in terms of total costs provides incentives to distributors to select the efficient combination of operating and capital costs and to exploit any opportunities to create synergies with other sectors. Long regulatory periods increase the power of such incentives.
- Incentives to innovation and inter-sectorial synergies: incentives for distributors to deploy innovative technologies should be mainly a by-product of regulatory schemes targeting outputs, rather than being pursued through schemes targeting specific technologies or solutions. This would ensure that only innovation directly impacting on the value of the service for network users be implemented and, more generally, that regulation be technology neutral. The same recommendation holds for incentives to exploit synergies between distribution investments and the supply of non-energy local services;

- Re-openings and allowed revenue indexation: allowed revenue updates during the regulatory period should be triggered only by very major events, whose occurrence and impact on cost are clearly beyond the distributor's control. Some major cost items beyond the distributors control are known to be variable in time. When robust indexes of such costs are available, the distributor's allowed revenues should be parametrized, in order to reduce the risk borne by distributors.

Recommendation 4: efficient distribution tariffs should be designed to send long term incremental cost signals to consumers. In general, this requires that:

- Costs for consumer specific infrastructures be covered through standing charges or connection charges;
- Costs for shared infrastructures be split among network users based on each one's contribution to the infrastructure's peak load.

This recommendation is based on the assumption – which should be investigated empirically on a case by case basis – that distribution capacity shortages are optimally addressed through network upgrades and that therefore scarcity conditions in distribution are typically transitory. If, instead, congestions turned out to be a permanent feature of optimally dimensioned distribution systems, experience in transmission and economic theory suggest that dynamic pricing systems are far more effective in rationing available capacity than time-of-use tariffs set long before real time.

We are not aware of any applications of dynamic charging to distribution services; therefore, any assessment of the relative merits of alternative models is speculative. However, experience in transmission pricing suggests that schemes addressing transportation capacity scarcity via locational energy price differentiation are more effective than schemes based on dynamic network charges.

The report is organised as follows. Section 2 presents a set of indicators allowing the characterisation and comparison of the activities and performance of European electricity and gas distributors. Section 3 contains the discussion of the economic principles governing tariff regulation. Section 4 contains our analysis of the distribution tariffs and their methodologies or terms and conditions in EU Member States. In Section 5, we identify and discuss best practices on distribution tariff design. Section 6 reports the results of our analysis of the tariff structures by network user groups in EU Member States. In Section 7 we develop recommendations for the Commission.

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Disclaimer

2. Task 1- Indicators of the cost-effectiveness of the DSOs and their operational efficiency

2.1. Introduction

The merits of assessing DSO cost effectiveness and operative efficiency

This task is being undertaken with the aim of supporting the European Commission in analysing DSO performance and identifying policy options concerning electricity and natural gas distribution in Europe.

The development and application of well-designed indicators of DSO inputs, outputs and costs has several important merits.

Firstly, indicators can reveal specific and important details of the structure of a distribution network. Given the substantial differences in distribution network structures between European countries, indicators can play a role in helping the Commission to gain a detailed understanding of the variations in network structures throughout Europe.

Beyond helping to understand the differences in physical network structure, well-designed indicators can also shed light on various difficult-to-measure characteristics of distribution networks, including: the types of services offered and the quality of those services; the degree to which distributed generation capacity (including renewable generation) is integrated into the network system; and the use and effectiveness of flexibility measures by DSOs.

Thirdly, understanding the relationship between the inputs and outputs of distribution activities and distribution costs is not straightforward. This is partly a consequence of the multiple objectives of DSOs, while the numerous inputs and outputs of distribution activities can make it difficult to understand the exact costs associated with each and every distribution input and output without undertaking a detailed analysis.

Well-designed indicators should also be replicable, meaning that they can be employed repeatedly in future years, thereby allowing the Commission to monitor the evolution of DSOs´ performances over time. This is important for several reasons. For instance, indicators that provide an accurate means of monitoring performance change over time can help the Commission and DSOs to evaluate the effectiveness of measures (best practice or otherwise) implemented by DSOs with the intention of addressing issues that were previously identified as requiring attention. In the event that implemented measures are not delivering the anticipated performance improvements, they can be adjusted, discontinued or replaced.

Lastly, performance indicators can be used within the Commission´s overall analysis of the electricity and natural gas distribution sectors throughout the EU. That is, indicators can be used to build-up an overall picture of sector performance, and also to focus in on specific aspects of service provision performance that may be of particular interest. This can then play a crucial role in the Commission´s development of policy.

The assessment of DSOs´ performances, and areas where improvements are needed, is central to ensuring that optimal policy decisions can be made. That is, policies can be shaped to address those areas identified as needing improvement as well as addressing key sector objectives. Moreover, the effectiveness of DSOs under implemented policies can be analysed at various points over the policy´s lifetime using well-designed assessment techniques. This can allow the effectiveness of policies to be critiqued, and on-going adjustments and modifications to the policy can consequently be made if required.

The usefulness of streamlined indicators at EU level is remarkable for national and lower level governments as well. A reliable international benchmarking of efficiency and quality performances can decisively help them to address the main challenges and goals facing the industry, and to take action if necessary on its structure and regulatory principles, including with a view to pursue social and environmental objectives.

Differences between Member States´ regulatory approaches

There are two main Directives relating to common rules for the internal energy markets in Europe for electricity (2009/72/EC) and natural gas (2009/73/EC). Both Directives offer significant flexibility to NRAs in their development of regulations for electricity and natural gas distribution pricing. These Directives specify that NRAs should take on the duty of *´fixing or approving, in accordance with transparent criteria, transmission or distribution tariffs and their methodologies´*.[1]

In relation to efforts to improve the cost-effectiveness of distribution activities, the same Directives make requirements on NRAs to *´ensure that transmission and distribution system operators are granted appropriate incentive, over both the short and long term, to increase efficiencies, foster market integration and security of supply and support the related research activities*.´[2]

Given the flexibility provided by the electricity and natural gas Directives for each country to pursue its preferred approach to distribution pricing and general regulation of the sector, it is the case that important differences exist between the regulatory approaches to electricity and natural gas distribution in individual Member States. Whilst on the one hand this allows national preferences to be pursued by each country (allowing countries to theoretically adopt the approach which it perceives to be the most efficient or comfortable for its individual situation), it also severely limits the potential to use inference benchmarking techniques to analyse and compare overall DSO performance between countries, already hindered by legislative, fiscal and other country specific contexts.[3] This is an important aspect in relation to the Commission's perspective, in relation to its analysis and the development of optimal policies.[4]

There are various reasons why it is problematic to use statistical and other benchmarking techniques to compare performance between countries. For example, the use of diverse definitions of key variables across Member States means that attempts to compare certain aspects of performance may be compromised due to different countries´ interpretations of what exactly is to be measured. This problem is particularly pronounced in relation to cost comparisons across countries due to the role of national factors in the definition of costs, which may be related, for example, to regulatory

[1] Article 37(1)(a) of Directive 2009/72/EC and Article 41(1)(a) of Directive 2009/73/EC

[2] Article 37(8) of Directive 2009/72/EC and Article 41(8) of Directive 2009/73/EC

[3] It is worth noting, however, that measures are currently being taken with a view to addressing this challenge. CEER has a work stream ongoing which is looking at the issue of benchmarking DSOs and TSOs across Member States in order to develop its understanding of best practice.

[4] Such information will be valuable to the Commission in several respects. For instance, a detailed understanding of specific best practices in regulatory measures for promoting and facilitating the adoption of technologies and practices for ´smarter´ distribution systems will help the Commission to offer guidance and recommendations to Member States whilst also respecting individual countries´ characteristics and preferred approaches.

regimes for labour and country-specific taxation approaches. Moreover, it is also the case that significant variations exist in the architecture, size and conditions of countries´ distribution systems.

Given these complexities and challenges, the use of indicators that can provide a comprehensive and detailed picture of the inputs and outputs of distribution activities and distribution costs could be a more sensible and effective way of analysing DSO performance. Performance indicators have excellent potential for identifying the relevant issues to be analysed by the Commission and others, and can play an important role in helping the Commission in its development (and on-going review) of policies.

The new needs that assessments and benchmarking have to take into account

The assessment and benchmarking techniques in use at any given time are generally designed to measure (and allow comparisons to be made of) the factors considered to be most significant. These factors are generally linked to, and reflective of, the strategic aims and objectives of the sector.

The priority objectives of the electricity and natural gas distribution sectors in the EU have shifted in comparison to what were traditionally considered to be the central objectives of the sectors. This is perhaps most clearly reflected by a ´then and now´ comparison of the responsibilities falling on DSOs.

The traditional role of DSOs can be generally summarised as their being transporters of electricity and natural gas from transmission networks to end-consumers. This meant that the sectors´ policy objectives (and hence the regulatory regimes) focused on three central topics, namely:

1. Ensuring that the population had a very high level of (overall) access to services, mainly through ensuring a high rate of connections;
2. Promoting improvements in the productivity of service provision, and sharing the benefits of those improvements among electricity and natural gas consumers; and
3. Ensuring that electricity and natural gas supply was of an overall high quality of service.

DSOs nowadays have certain specific responsibilities (and new technologies which allow them) to deliver smarter and more integrated distribution networks in a timely and more efficient way. That is, whilst DSOs should continue to ensure high quality of service provision, high levels of access and efficiency improvements, there is also a clear drive to create the conditions necessary for more integrated and intelligent distribution networks to be created and to operate. Specifically, a number of tools to fulfil the general sector objectives (stated above) are emerging or increasing in importance, including:

- Developing financial measures which encourage more efficient consumption of electricity and natural gas by consumers;
- Removing obstacles to DSOs' implementation of innovative (non-traditional) investment options;
- Designing financial measures which incentivise DSOs to make investments which provide the most cost-effective solutions for all network users as a whole;
- Ensuring that adequate (technical and other) standards are implemented, particularly for new technologies and modes of operating distribution systems;

- Addressing data privacy and security issues which arise from the use of innovative technologies and techniques;
- Removing obstacles to DSOs´ implementation of innovative network tariffs to incentivise the more efficient use of the network;
- Improving DSOs´ abilities to identify and address any potential emerging issues with smarter, advanced technologies and applications such as innovative storage applications; and
- Incorporating (potentially) large-scale renewable and embedded generation into distribution networks; and
- Incorporating demand and supply side flexibility resources into distribution networks.

It is clear that the shifts in the overall objectives of the electricity and natural gas sectors, and DSOs´ roles and responsibilities, means that new measurement scales are called for, in order to ensure that assessments do indeed measure the current performance factors of importance.

2.2. Criteria for identifying and selecting indicators

The identification and selection of indicators of DSOs´ cost effectiveness and operative efficiencies is of central importance to being able to adequately assess and benchmark DSOs´ performance. A wide variety of performance indicators could be potentially chosen for use, but it is critical to the overall success of the performance evaluation process to ensure that the best ones are selected. In this context, the optimal indicators are those that will allow meaningful and objective comparisons of DSO performance, within each country, as well as facilitating cross-country comparisons.

For practical reasons it is necessary to select a relatively small number of variables that are capable of explaining performance and a large share of incurred distribution costs in a meaningful way. Consequently, criteria should be devised to select the most useful indicators.

It is essential that indicators are *relevant*. That is, an indicator must be able to answer a specific research question of interest. In other words, they should be comprehensible and their potential to assess a certain clearly defined aspect of performance should be beyond question.

An important characteristic of indicators is also that they should be *measurable*. In practice this means that an indicator should measure and assess a specific aspect of distribution for which the required information is available. A certain degree of variation in data availability of different countries is inevitable, hence indicators that are more widely available across countries should have priority over those indicators whose availability, and practical applicability, is likely to be patchy or inexistent.

In the selection of indicators to be used, priority should also be given to those that *facilitate objective assessments*. For example, indicators that use a calculation methodology that does not eliminate ´background´ or other country-specific factors that are not related to the aspect being measured should be avoided.

Finally, indicators should *facilitate comparisons* between the distribution systems and DSOs of different countries, notably to allow benchmarking of performance evolution over time.

2.3. Proposed relevant inputs

Before describing the different indicators which could be used to assess and benchmark the cost-effectiveness of the DSOs and their operational efficiencies, it is important to clearly define each of the relevant key input variables (i.e. the inputs which are used in the calculations of indicator values). These are considered below, firstly for electricity distribution, and then for natural gas distribution.

Furthermore, some additional elements must be taken into account when employing and evaluating the indicators, such as:

- The unbundling status in each case (ownership, legal, etc.);
- Type of regulator existing in the country;
- Type of existing regime (concession, its duration, or license, licensing authority, etc.); and
- Other services provided by the DSO (e.g. gas, water, waste collection, local transport, etc.).

Electricity: input variables

Electricity sector-related input variables are grouped into four distinct areas, namely:

- Variables of the electricity firm´s products and services (Table 1);
- Variables of the electricity firm´s quality of service (Table 2);
- Variables of the electricity distribution network typology (Table 3); and
- Variables of cost (Table 4).

Table 1: Variables of the electricity firm´s products and services

Variable	Description	Unit of measurement	Data / information source
Connected end-consumers (residential)	Number of customers defined as residential customers	Count	DSO Annual Reports
Connected end-consumers (non-residential)	Number of customers defined as industrial or commercial customers	Count	DSO Annual Reports
Metered consumers	Total number of consumers that have a meter installed and properly working, by voltage, in the last 3 years, including type of meter	Count	DSO Annual Reports
System-connected embedded generation	Number and peak power of embedded generation connected by voltage	Count and MW	DSO Annual Reports
Storage capacity of the distribution grid	The electricity storage capacity of the distribution grid under consideration	MW	DSO Annual Reports
Stored energy on distribution grid	The amount of electricity stored on the distribution grid	MWh	DSO Annual Reports
Peak demand	Demand level during peak hour	MW	DSO Annual Reports
Demand flexibility	Quantity of controllable electricity load (flexibility)	MW	DSO Annual Reports
Electricity supplied	Amount of electricity delivered in a year per each typology of customers	MWh	DSO Annual Reports
Balancing duties	DSOs´ duties related to system balancing	No specific units (qualitative information)	Network Regulations / Grid Codes
Electric car charging points	Number of car charging points provided within the network	Count	DSO Annual Report; Municipal Authority Reports
DSO Electric car charging points	The share (%) of total electric car charging points which are owned by DSOs	%	DSO Annual Reports Municipal Authority Reports
EV demand	EV chargers total rated power	MW	DSO Annual Reports
EV injection	The amount of electricity which can be obtained by the distribution network from Evs	MWh	DSO Annual Reports
Smart meters	Number and type of smart meters installed	Count	DSO Annual Reports

Variable	Description	Unit of measurement	Data / information source
MW of distributed generation	The total electrical generation capacity of all distributed generation connected to the network	MW	DSO Annual Reports
Number of customers on time-of-use/critical peak/real-time dynamic pricing	The total number of customers with supply agreements with a specific DSO which have pricing contracts based on time-of-use/critical peak/real-time dynamic pricing	Count	DSO Annual Reports

Table 2: Variables of the electricity firm´s quality of service

Variable	Description	Unit of measurement	Data / information source
Interruptions	Number and duration of relevant interruptions occurred in a year, based on SAIFI, SAIDI or similar	Count, MWh and minutes/year	DSO Annual Report; NRA Reports
Technical losses	Amount of energy accounted as technical losses	MWh	DSO Annual Reports
Commercial losses	Amount of energy accounted as commercial losses	MWh	DSO Annual Reports
Number of distribution forced outage events	Number of events in which there is a forced outage in the distribution network	Count	DSO Annual Reports
Output-based regulation	Incentives, revenue or tariff components that are related to quality of service parameters	Qualitative description	NRA Publications; DSO Reports
Smart meters incentives framework	A description of any relevant mechanisms in place in the event that incentives to install new smart meters are in operation	Qualitative description	Government Ministry Reports; NRA Publications; DSO Reports

Table 3: Variables of the electricity distribution network typology

Variable	Description	Unit of measurement	Data / information source
Overhead lines	Number of kilometres of lines controlled and operated by the distributors by voltage, in the last 3 years	Km	DSO Annual Reports
Underground lines	Km of underground lines controlled and operated by the distributors by voltage, in the last 3 years	Km	DSO Annual Reports
Distribution power transformers	Number and power of total power transformers installed	Count and MW	DSO Annual Reports
Smart grid projects	Number and value (in both cost and NPV) of projects	Count, number of metering points involved, € (cost and NPV)	DSO Annual Reports; Direct consultation with DSO
New technologies incentives framework	Any scheme for the connection or implementation of new infrastructure (electric vehicles, local energy storage, etc.) that is operated or under development	Qualitative description	DSO Annual Reports; NRA publications
Area size	Total surface area of supplied municipalities	Km^2	DSO websites and publications
Area population	Total Number of inhabitants of the served area	Count	DSO publication or national official statistics
Area characteristics	Main characteristics of the served area	Qualitative description: (Mostly) flat / hilly / mountainous / small islands	DSO websites and publications
Share of urban customers	Share of connected customers located in municipalities with more than 15,000 inhabitants	%	DSO websites and publications

Table 4: Variables of cost

Variable	Description	Unit of measurement	Data / information source
OPEX	OPEX includes all regulated operating expenditure required for the provision of regulated distribution services. It is fully recovered in the year in which the expenditure is incurred.	€/year	DSO Annual Reports; NRA Reports
CAPEX	Regulated expenditure for the creation of assets required for the provision of regulated distribution services. Costs are recovered through depreciation over several years	€/year	DSO Annual Reports; NRA Reports
RAB	Value of the official regulated asset base at the end of last year	€	DSO Annual Reports; NRA Reports
RAB valuation method	Methodology used for RAB valuation by tariff methodology	(Book value, Current cost, MEAV, other to be specified	DSO Annual Reports; NRA Reports
X factor	Productivity improvement factor	%/year general, %/year specific	DSO Annual Reports; NRA Reports
Incentives	Incentives provided for, for example, the improvement of the quality of services; smart meters; connection of distributed generation, biogas; other distributed energy resources (electric vehicles, local energy storage); use of benchmarking techniques; and productivity improvement factor(s)	Qualitative descriptions	DSO Annual Reports; Government Ministry Reports
Labour cost	The amount which is directly or indirectly given to employees defined as labour cost in the balance sheet	€/year	DSO Annual Reports
Revenues	Revenues received (to be specified from: connection activities, distribution activities, other)	€/year	DSO Annual Reports; NRA Reports
Customer care personnel	Number of employees in the customer care unit	Count	DSO Annual Reports
Total employees	Number of employees in the DSO	Count	DSO Annual Reports
Residential distribution tariffs level	Tariff levels for residential customers (please provide Table by customer classes if appropriate)	€c / kWh	Government Ministry Publications; DSO Annual Reports
Commercial distribution tariffs level	Tariffs level for commercial customers (please provide Table by customer classes if appropriate)	€c / kWh	Government Ministry Publications; DSO Annual

Variable	Description	Unit of measurement	Data / information source
			Reports
Industrial distribution tariffs level	Tariffs level for industrial customers (please provide Table by customer classes if appropriate)	€c / kWh	Government Ministry Publications; DSO Annual Reports
Residential average standing charge	Tariffs level for residential customers (please provide Table by customer classes if appropriate)	€ / kWh	Government Ministry Publications; DSO Annual Reports
Commercial average standing or load-related charge	Tariffs level for commercial customers (please provide Table by customer classes if appropriate)	€ / kWh	Government Ministry Publications; DSO Annual Reports
Industrial average standing or load-related charge	Tariffs level for industrial customers (please provide Table by customer classes if appropriate)	€ / kWh	Government Ministry Publications; DSO Annual Reports
Connection charges	Average amount required by the DSO for a new connection by voltage and by customer type or rated power	€	DSO Annual Reports
Average rate of return	Weighted Average Cost of Capital, or other as applicable; before tax	%	NRA Reports; DSO Annual Reports
Number of regulatory period	Number of regulatory period	Count	NRA Reports; DSO Annual Reports
Length of regulatory period	Length of current regulatory period (please specify if any change is expected)	Years	NRA Reports; DSO Annual Reports
Awards / penalties	The amount of awards or penalties coming from the mechanism used to improve the DSO's quality performance or other objectives (output-based regulation)	€	DSO Annual Reports

Natural gas: input variables

The proposed relevant inputs for natural gas DSO performance assessment are similar to those described for electricity DSOs; however, they also include some differences, due to specific characteristics of natural gas distribution. Natural gas sector-related input variables are also grouped into four distinct areas, namely:

- Variables of the natural gas firm´s products and services (Table 5);

- Variables of the natural gas firm´s quality of service (Table 6);
- Variables of the natural gas distribution network typology (Table 7); and
- Variables of cost (Table 8).

Table 5: Variables of the natural gas firm´s products and services

Variable	Description	Unit of measurement	Data / information source
Connected end-consumers (residential)	Number of customers defined as residential customers	Count	DSO Annual Reports
Connected end-consumers (non-residential)	Number of customers defined as industrial or commercial customers	Count	DSO Annual Reports
Metered consumers	Total number of consumers that have a meter installed and properly working, by size, and time of measurement (daily, hourly)	Count	DSO Annual Reports
Distributed production connected	Cubic meters of biogas/bio-methane connected by size and typology	Cm	DSO Annual Reports
Peak demand	Demand level during peak hour or day	Cm/hr or cm/day	DSO Annual Reports
Demand flexibility	Quantity of interruptible gas consumption	Cm	DSO Annual Reports
Storage capacity	Storage capacity under DSO control	Mcm	DSO Annual Reports
Gas delivered	Amount of gas delivered in a year per each typology of customer	Mcm	DSO Annual Reports
Meters	Total number of meters installed	Count	DSO Annual Reports
Daily or hourly metering	Total number of meters with daily or hourly measurement and related consumption	Count (specify if hourly) and (if possible) cm	DSO Annual Reports
Pressure/temperature corrected meters	Total number of meters with pressure/temperature corrected measurement and related consumption	Count and (if possible) cm	DSO Annual Reports
Smart meters	Number and type of smart meters installed	Count	DSO Annual Reports

Table 6: Variables of the natural gas firm´s quality of service

Variable	Description	Unit of measurement	Data / information source
Interruptions	Number and amount of relevant interruptions occurred in a year	Count and lost cm	DSO Annual Report; NRA Reports
Checks on network	Percentage of safety checks on network per year	Count and MWh	DSO Annual Report; NRA Reports
Leakages	Number and amount of detected leakages occurred in a year	Count and MWh	DSO Annual Report; NRA Reports
Emergency interventions	No of emergency interventions after customers' or third party calls	Count	DSO Annual Reports
Technical losses	Amount of energy/cm accounted as technical losses	MWh or cm	DSO Annual Reports
Commercial losses	Amount of energy/cm accounted as commercial losses	MWh or cm	DSO Annual Reports
Output-based regulation	Incentives, revenue or tariff component that are related to quality of service parameters	Qualitative description	NRA Publications; DSO Reports
Smart meters incentives framework	A description of any relevant mechanisms in place in the event that incentives to install new smart meters are in operation	Qualitative description	Government Ministry Reports; NRA Publications; DSO Reports

Table 7: Variables of the natural gas distribution network typology

Variable	Description	Unit of measurement	Data / information source
Pipelines	Km of pipelines controlled and operated by the distributors, by pressure class	Km	DSO Annual Reports
Distributed generation incentives framework	Any scheme to boost the connection of biogas / biomethane production (FiT scheme, etc.)	Description of the incentive level revision methodology/timing and length of the incentives	DSO Annual Reports; NRA Reports

Area size	Total surface area of supplied municipalities[5]	Km^2	DSO websites and publications
Area characteristics	Main characteristics of the served area	(Mostly) flat / hilly / mountainous / small islands	DSO websites and publications
Area population	Total No. of inhabitants of served area	Count	DSO publication or national official statistics
Share of urban customers	Share of connected customers located in municipalities with more than 15,000 inhabitants	%	DSO websites and publications

Table 8: Variables of cost

Variable	Description	Unit of measurement	Data / information source
OPEX	OPEX includes all regulated operating expenditure required for the provision of regulated distribution services. It is fully recovered in the year in which the expenditure is incurred.[6]	€/year	DSO Annual Reports; NRA Reports
CAPEX	Regulated expenditure for the creation of assets required for the provision of regulated distribution services. Costs are recovered through depreciation over several years	€/year	DSO Annual Reports; NRA Reports
RAB	Value of the official regulated asset base at the end of last year if available	€	DSO Annual Reports; NRA Reports
RAB valuation method	Method used for RAB valuation by tariff methodology	(Book value, Current cost, MEAV, other to be specified	DSO Annual Reports; NRA Reports
X factor	Productivity improvement factor	%/year general, %/year specific	DSO Annual Reports; NRA Reports
Incentives	Incentives provided for: the improvement of the quality of services; smart meters; connection of biogas; local storage); use of benchmarking techniques; and productivity improvement factor(s)	Qualitative descriptions	DSO Annual Reports; Government Ministry Reports
Labour cost	The amount which is directly or indirectly given to employees defined as labour cost in the balance sheet	€/year	DSO Annual Reports

[5] By this we mean the geographic area (km^2) of the municipality which is supplied by a DSO.
[6] Different arrangements may be used in the case where Totex remuneration is used.

Variable	Description	Unit of measurement	Data / information source
Revenues	Revenues received (to be specified from: connection activities, distribution activities, other)	€/year	DSO Annual Reports; NRA Reports
Customer care personnel	Number of employees in the customer care unit	Count	DSO Annual Reports
Total employees	Number of employees in the DSO	Count	DSO Annual Reports
Residential distribution tariffs level	Tariff levels for residential customers (please provide Table by customer classes if appropriate)	€c / kWh	Government Ministry Publications; DSO Annual Reports
Commercial distribution tariffs level	Tariffs level for commercial customers (please provide Table by customer classes if appropriate)	€c / kWh	Government Ministry Publications; DSO Annual Reports
Industrial distribution tariffs level	Tariffs level for industrial customers (please provide Table by customer classes if appropriate)	€c / kWh	Government Ministry Publications; DSO Annual Reports
Residential average standing charge	Tariffs level for residential customers (please provide Table by customer classes if appropriate)	€ / kW	Government Ministry Publications; DSO Annual Reports
Commercial average standing or capacity-related charge	Tariffs level for commercial customers (please provide Table by customer classes if appropriate)	€ / kW	Government Ministry Publications; DSO Annual Reports
Industrial average standing or load-related charge	Tariffs level for industrial customers (please provide Table by customer classes if appropriate)	€ / kW	Government Ministry Publications; DSO Annual Reports
Connection charges	Average amount required by the DSO for a new connection by voltage	€	DSO Annual Reports
Average rate of return	Weighted Average Cost of Capital, or other as applicable; before tax	%	NRA Reports; DSO Annual Reports
Number of regulatory period	Number of regulatory period[7]	Count	NRA Reports; DSO Annual Reports

[7] By this we refer to the number of regulatory periods which have been in effect since the first regulatory period commenced, up to and including the current regulatory period (e.g. if 4 regulatory periods have previously been in effect but since stopped, the currently regulatory period is the 5th regulatory period).

Variable	Description	Unit of measurement	Data / information source
Length of regulatory period	Length of current regulatory period (please specify if any change is expected)	Years	NRA Reports; DSO Annual Reports
Awards / penalties	The amount of awards or penalties coming from the mechanism used to improve the DSO's quality performance or other objectives (output-based regulation)	€	DSO Annual Reports

2.4. Proposed indicators

The project team proposes to use a range of indicators of DSOs´ cost effectiveness and operative efficiency, which are set out below. Each indicator has been considered in relation to its ability to meet the selection requirements explained in section 2, specifically:

- The variation (improvement) of the indicator would determine a quantifiable benefit to grid users and, in general, society as a whole;
- It is possible to determine (measure or calculate) the value of the index in a sufficiently accurate and objective way;
- The value of the index can be influenced (even if to a limited extent) by the network operator or the system operator; this includes metering. It is also specified that performance targets should be cleansed of external effects outside the control of network operators; and
- The index should be as far as possible, technology neutral.

For each indicator, an explanation of what is being measured (and the output/result of the measurement) is provided, as well as a description of the specific method (formula) used to calculate the indicator value.[8]

Suggested indicators are commonly used (or considered for use) in benchmarking exercises. Whereas simple indicators may provide useful information, their separate use may be misleading. For example, comparison of employees/customers ratios may be meaningless unless characteristics of served areas are also considered, which are reflected in population density or network length per customer, etc. Generally speaking, multivariate analysis is recommended. The following indicators should be considered as preliminary information in order to identify the most relevant issues and set up an analysis of service effectiveness or efficiency.

Indicators for electricity DSOs are provided in Table 9 and those for natural gas DSOs are provided in Table 10.

[8] It should be understood that these indicators are not used directly to assess DSO performance; rather, performance is assessed in terms of outputs. The use of input-based indicators, however, provides a useful means of normalizing the outputs in different Member States, in order to allow some degree of comparison between Member States to be made.

Table 9: Proposed indicators for electricity DSOs

Indicator name	Formula	Explanation	Uses and limitations
Indicators related to customer base and the provision of customer services			
Average number of customers	[Total num. of customers at start of period (connections) + total number of customers at end of period] / 2	This is an indicator on the average number of customers	Average number of customers for the benchmarking period.
Population density	Population / surface area (Inhabs./Km^2)	This is likely to affect costs of service in several ways	Benchmarking
Customer density	Total customers / Km of network	This is an indicator on customer density in a given area	Customer density
Indicators related to revisions and updates of distribution network technologies			
Updating of meter technology	Meters replaced in a year / meters in service at the beginning of the same year	This is an indicator of the rate at which meters are replaced	Meter replacement rate
Distribution transformer utilisation	(Electricity sold (MWh) * 100) / (total distribution transformer capacity (MVA) * 8760h)	This indicator looks at the total energy delivered to consumers on the low voltage network through distribution transformers. Total Distribution Transformer Capacity is calculated by adding up the capacity (nameplate rating) of all distribution transformers installed on the distribution network	The Distribution Transformer Utilisation indicates the effectiveness of distribution planning in matching transformer capacity with demand. A low utilisation implies a greater investment in distribution transformers. A higher utilisation implies higher efficiency in capital outlay on the distribution network (or on the other side of the scale, deferred capacity upgrade and erosion of security margins)
Indicators related to technical aspects and characteristics of the distribution network			
Load factor	(Annual electricity supplied (MWh) / 8760) / Peak annual demand (MW)	Load factor is a ratio of average annual load to maximum annual load per DSO level. This indicator measures how much power is supplied on the average per unit of peak demand.	Load factor provides information on how efficiently the power system equipment is used and, to a certain extent, helps understand how close the power supply system is to being overloaded. When load factor is high (i.e., average supply is only marginally below peak demand), equipment usage efficiency is high and vice

Indicator name	Formula	Explanation	Uses and limitations
			versa. At the same time, when load factor is close to 100%, the system might be at its capacity limit and could collapse with potential increase in peak demand.
Underground cable ratio	Length of underground cables/total network length	Important cost and quality factor	Benchmarking of most relevant solution to improve urban quality
Storage	Average stored energy / energy distributed	The ratio of stored energy to energy distributed	A comparison of the electricity which is stored to the electricity distributed
	Storage capacity /peak demand	The ratio of network storage capacity to peak demand of the network	The proportion of peak demand which can be met by stored electricity
EV	EV demand / total demand	The ratio of EV chargers total rated power to peak demand of the network	The potential maximum proportion of network total demand which comes from EVs
	EV injections / total demand	The ratio of electricity which can be obtained from EVS to total electricity demand	The potential maximum proportion of total network demand which could be met from electricity supplied by EVs
Demand flexibility coverage	MW of flexible demand / peak demand	The ratio of demand which is flexible to peak demand	Proportion of peak demand which could be met by flexible demand
DG coverage	MW of DG / peak demand	The ratio of DG generation capacity to peak demand on the network	The potential maximum proportion of peak demand which could be met by DG
	MW of DG / min demand	The ratio of DG generation capacity to the minimum demand level	The potential maximum proportion of minimum network demand which could be met by DG. Also provides some indication of the likelihood for DG to be curtailed in periods of minimum demand
Reverse Power Flow	((Number of hours in which there is a flow inversion in a primary substation or a given HV/MV transformer) / 8760) *100	The % of hours in which there is a flow inversion in a primary substation or a given HV/MV transformer	Indicates the relative amount of time in year in which there is reverse power flow in a primary substation
Indicators of service provision performance			
Distribution Reliability	(Number of distribution forced outage events (events) / length of distribution line (Km)) * 100	This indicator looks at forced outage events per 100 km of distribution lines and cables.	Reliability of the distribution network

Indicator name	Formula	Explanation	Uses and limitations
SAIFI[9]	Total Customer Interruptions / Average Number of Customers (connections)	System Average Interruption Frequency Index: The 'Total Customer Interruptions' is the sum of the customer interruptions for each outage including both forced and planned interruptions. A customer interruption for a power outage is the total customers interrupted for the event	SAIFI indicates the average number of outages a customer experienced for the period
SAIDI[9]	Total Customer Interruptions Duration Interrupted (customer Hr) / Average Number of Customers (connection)	System Average Interruption Duration Index: Total Customer Interruptions Duration Index is found by summing the customer interruptions duration for each customer interruption event. This includes both planned and forced events.	SAIDI indicates the average power outage duration experienced by a customer during the benchmarking period
CAIDI	Sum of customer-minutes off for all sustained interruptions / Total n. of customers affected by the sustained interruptions	Customer Average Interruption Duration Index: CAIDI is the weighted average length of an interruption for customers affected during a specified time period	CAIDI indicates the duration of outages related to the numbers of costumers
Distribution losses	(energy input LESS energy billed to consumers in kWh / energy input in kWh) * 100	Distribution losses (Technical + Commercial losses): is the difference between energy supplied at the input points and energy billed to customers in percentage terms for a particular period. Electricity Delivered to the Distribution Network (input point) is the total energy measured at the demarcation points between transmission and distribution. Where a utility does not have a transmission network, the electricity delivered to the Distribution Network would be equal to the Net Generation.	Efficiency of distribution infrastructure

[9] The SAIDI and SAIFI indicators of service continuity could be further separated and elaborated, taking into account the work developed in recent years by CEER benchmarking electricity DSO quality of service. For instance, it could also be possible to calculate SAIDI and SAIFI values where ´planned interruptions´ and ´forced / unplanned interruptions´ are considered separately, thereby generating separate SAIDI and SAIFI values for each type of network interruption event.

Indicator name	Formula	Explanation	Uses and limitations
Curtailment[10]	DG not withdrawn due to congestion and/or security risk	Curtailment: this is the time in which a DG could be generated but it is halted from doing so by human decision, due to the risk of congestion and/or security risk. Curtailment is expressed in terms of the proportion of time in which a unit could be generating but is curtailed	Proportion of time in which a DG unit is curtailed / prevented from generating electricity
Indicators of financial aspects and costs			
Distribution O&M costs	Distribution O&M costs (€) / Length of distribution line (Km)	Distribution Operating & Maintenance costs related to the length of the distribution network	The total cost of operating and maintaining the distribution network on a per km line (overhead line and underground cable). This indicator should be carefully interpreted as it does not include the age of the network.
Actual debt to equity ratio	Long term debt\non-current liability (€) * 100 / Equity\Net assets\Capital reserves + Long term debt\ non-current liability	This looks at the gearing of the business. Gearing is a measure of financial leverage, demonstrating the degree to which a firm's activities are funded by the owner's funds versus creditor's funds	The higher the gearing, the greater the risk. When the business is performing well higher returns are generated for the owners. When losses are incurred the impact on the owner is increased. The optimum gearing ratio is specific for each industry.
Rate of Return on Assets, actual and allowed by regulator	EBIT\Operating Profit (€) * 100 / Average non-current assets (€)	The rate of return on assets is the return generated from the investment in the assets of the business. Earnings Before Interest Tax (EBIT) is the operating profits generated by the business after all operating costs including depreciation have been deducted from the income.	The return generated from the investment in the assets of the business.
Return on Equity	Profit after tax\earning after tax (€) * 100 / Equity\net assets\capital reserves	Return on Equity is the returns generated by the business for the owners of the business. In most utilities in the Pacific the owners of the utility is the government. Profit after tax (PAT) is the profit after interest is paid on funds from debt financiers and tax is paid to Government.	The returns generated by the business for the owners of the business

[10] Note that no specific uniform judgment on DSO performance is made in relation to curtailment rate. For instance, in Member States which have a deep or relatively-shallow connection boundary, DSOs may be able to connect generators to the network on a curtailed contract which otherwise would not have been connected due to high connection costs. In such an example, the overall amount of distributed generation within the system is increased, which has positive benefits. As mentioned above, input-based indicators are used here as a means to normalize the outputs of different Member States, which allows inter-country comparisons to be made

Indicator name	Formula	Explanation	Uses and limitations
Current Ratio	Current assets (€) * 100 / Current liabilities (€)	Current ratio indicates the ability of a utility to meet its short term liabilities (liabilities due within 12 months). Where the ratio is less than 100%, there is a risk that should the suppliers and liability owners' call on payment the utility would not be able to make all payments	The ability of a utility to meet its short term liabilities
Labour cost efficiency	Total labour cost / customer	This indicator shows the average labour costs incurred per customer	The average labour costs of the DSO per customer.
Average supply cost	Total operating expenses (€) / Natural gas sold (cm)	This indicator shows the operating costs incurred per unit of electricity sold (expressed in € / cm)	Average distribution cost
Cost recovery	Operating revenue/costs	This indicator is the ratio of unit revenue to cost	Sustainability of cost levels/tariffs. It would reflect the price-cost-revenue collection relationship.
Opex recovery	Operating costs / revenue billed	The indicator of operating expenses covered by revenues is a ratio of operating costs to revenues billed, expressed as percentage.	It reflects if the utility is capable of recovering its current expenditures at the existing consumption level and tariffs. This indicator is below 100% if operational cost is covered by revenues. To be able to recover costs that include capital expenses (in addition to operating expenses) and to account for non-collection, this indicator should be noticeably below 100%.
Average Opex	Opex / MWh	This is the indicator of the average OPEX incurred per unit of electricity distributed	A measure of how much OPEX is incurred in distributing a unit of electricity. Its use is relevant in the context of multivariate analysis.
	Opex / connection	The ratio of OPEX incurred to connections within the distribution network	A measure of how much OPEX is incurred per connection (ratio) within the network (i.e. it is not a reflection of the OPEX incurred by each connection). Its use is relevant in the context of multivariate analysis.
	Opex / km	The ratio of OPEX incurred to the number of kilometres of network lines	A measure of how much OPEX is incurred in the context of the size/length of the network. Its use is relevant in the context of multivariate analysis.
Average Capex	Capex / MWh	This is the indicator of the average CAPEX costs incurred per unit of electricity distributed	A measure of how much CAPEX is incurred in distributing a unit of electricity. Its use is relevant in the context of multivariate analysis.
	Capex / connection	The ratio of CAPEX incurred to connections within the distribution network	A measure of how much CAPEX is incurred per connection (ratio) within the network (i.e. it is not a reflection of the OPEX incurred by each connection). Its

Indicator name	Formula	Explanation	Uses and limitations
			use is relevant in the context of multivariate analysis.
	Capex / km	The ratio of CAPEX incurred to the number of kilometres of network lines	A measure of how much CAPEX is incurred in the context of the size/length of the network. Its use is relevant in the context of multivariate analysis.
Indicators of related to the use of innovative tariffs			
Incentivising tariffs share	Percentage of consumers on time-of-use/critical peak/real-time dynamic distribution pricing	Percentage of total number of consumers on time-of-use/critical peak/real-time dynamic pricing	Proportion of total consumers which are on distribution ´incentivising tariffs´ at any given point in time.
Load changes	Measured modifications of electricity consumption patterns after new pricing schemes	Measured modifications of electricity consumption patterns after the introduction of new pricing schemes	Percentage change (+ = consumption increase; - = consumption decrease) in electricity consumption following the introduction of new pricing schemes[11].

[11] The formulation of this index depends on the issue that the innovative pricing scheme is meant to address. If, for example, the measure aimes to reduce withdrawals at certain times, load changes at those time will be measured by the index.

Table 10: Proposed indicators for natural gas DSOs

Indicator name	Formula	Explanation	Uses and limitations
Indicators related to customer base and the provision of customer services			
Average number of customers	(Total num. of customers at start of period (connections) + total number of customers at end of period) / 2	This is an indicator on the average number of customers	Average number of customers for the benchmarking period.
Population density	Population / surface area (Inhabs./Km^2)	This is likely to affect costs of service in several ways	Benchmarking
Customer density	Total customers / Km of network	This is an indicator on customer density in a given area[12]	Customer density
Productive natural gas usage	(Total commercial gas billed (MWh) + Total industrial gas billed (MWh) or Total other (productive) gas billed (MWh)) * 100 / natural gas sold (MWh)	This is an indicator for the natural gas used in economic productive way; it is the ratio of the commercial and industrial natural gas billed with the overall natural gas sold	It is assumed that the natural gas billed to commercial and industrial customers is productive for the economy. Based on this assumption, this indicator captures the productive economic impact of natural gas supply. It ignores the economic impact of domestic supply and other categories
Service coverage	(Number of households supplied (household) / Total number of household in country) * 100	This indicator gives the service coverage by the ratio of households supplied and households in the country	This indicator looks at the natural gas coverage with respect to the country served by the utility. It also indicates the potential market yet to be served by the utility
Indicators related to revisions and updates of distribution network technologies			
Real time meter reading	No. of meters with daily or hourly measurement/Total No. of meters	This explains the share of gas that is subject to precise reading and does not require estimation by load profiling	Availability of real time meter reading improves the estimation of consumption by suppliers and hence facilitates market balancing and liquidity

[12] This measure also encompasses technological choices which have been made in the area (including, for example, network redundancies)

Indicator name	Formula	Explanation	Uses and limitations
Distribution Reliability	(Number of distribution forced outage events (events) / length of distribution pipeline (Km)) * 100	This indicator looks at forced outage events per 100 km of distribution pipelines	Reliability of the distribution network
SAIFI	Total Unplanned Customer Interruptions / Average Number of Customers (connections)	System Average Interruption Frequency Index: The 'Total Customer Interruptions' is the sum of the customer interruptions for each outage including both forced and planned interruptions. A customer interruption for an outage is the total customers interrupted for the event	SAIFI indicates the average number of supply interruptions a customer experienced for the period
SAIDI	Total Unplanned Customer Interruptions Duration Interrupted (customer Hr) / Average Number of Customers (connection)	System Average Interruption Duration Index: Total Customer Interruptions Duration Index is found by summing the customer interruptions duration for each customer interruption event. This includes both planned and forced events.	SAIDI indicates the average supply interruption duration experienced by a customer during the benchmarking period
CAIDI	Sum of customer-minutes off for all sustained unplanned interruptions / Total n. of customers affected by the sustained interruptions	Customer Average Interruption Duration Index: CAIDI is the weighted average length of an interruption for customers affected during a specified time period	CAIDI indicates the duration of supply interruptions related to the numbers of costumers
Unaccounted for gas[13]	(Total billed gas plus own consumption) / total gas at the input point) * 100	Aggregate Technical & Commercial losses: this aggregate measure compares natural gas supplied to the distributor with natural gas sold to customers. The difference between these figures is the energy lost in distribution due to technical reasons (e.g., network leakages), commercial reasons (e.g., theft and unaccounted or unmetered sales) and errors in the estimation of consumers without daily or hourly meters..	Effectiveness in minimizing unrecoverable energy cost. The problem comes in estimating actual energy delivered to customers that are not metered, which is particularly common in rural areas. Energy purchased by unmetered customers can be estimated from the consumption of comparable, metered customers, or from substation metered data
Number of gas network inspections	Number of inspections undertaken in one year / total length of gas pipeline network	The number of gas inspections undertaken in one year as a proportion of the total gas pipeline network owned and operated by the DSO.	This is an indicator of the level of activity that each DSO makes regarding network safety inspections in its network.

[13] This is an indirect way of measuring gas leakages

Indicator name	Formula	Explanation	Uses and limitations
Odorising gas level testing	Number of tests of odorising gas levels / number of connection points	The number of tests undertaken of odorising gas levels within a year, as related to the number of connection points within the network	This is an indicator of the degree of safety inspection activity undertaken by a DSO, and in this case specifically related to odorising gas levels
Indicators of financial aspects and costs			
Distribution O&M costs	Distribution O&M costs (€) / Length of distribution pipeline (Km)	Distribution Operating & Maintenance costs related to the length of the distribution network	The total cost of operating and maintaining the distribution network on a per km pipeline. This indicator should be carefully interpreted as it does not include the age of the network.
Debt to Equity Ratio	Long term debt\non-current liability (€) * 100 / Equity\Net assets\Capital reserves + Long term debt\non-current liability	This looks at the gearing of the business. Gearing is a measure of financial leverage, demonstrating the degree to which a firm's activities are funded by the owner's funds versus creditor's funds	The higher the gearing, the greater the risk. When the business is performing well higher returns are generated for the owners. When losses are incurred the impact on the owner is increased. The optimum gearing ratio is specific for each industry. For the utility business in the Pacific a Benchmark of 50% is deemed suitable.
Rate of Return on Assets	EBIT\Operating Profit (€) * 100 / Average non-current assets (€)	EBIT\Operating Profit (€) * 100 / Average non-current assets (€)	The return generated from the investment in the assets of the business.
Return on Equity	Profit after tax\earning after tax (€) * 100 / Equity\net assets\capital reserves	Return on Equity is the returns generated by the business for the owners of the business. In most utilities in the Pacific the owners of the utility is the government. Profit after tax (PAT) is the profit after interest is paid on funds from debt financiers and tax is paid to Government.	The returns generated by the business for the owners of the business
Current Ratio	Current assets (€) * 100 / Current liabilities (€)	Current ratio indicates the ability of a utility to meet its short term liabilities (liabilities due within 12 months). Where the ratio is less than 100%, there is a risk that should the suppliers and liability owners' call on payment the utility would not be able to make all payments	The ability of a utility to meet its short term liabilities
Average supply cost	Total operating expenses (€) / Natural gas sold (cm)	This indicator shows the operating costs incurred per unit of electricity sold (expressed in € / cm)	The unit costs of supplying natural gas
Labour cost efficiency	Total labour cost / customer	This indicator shows the average labour costs incurred per customer	The average labour costs of the DSO per customer.
Cost recovery	op. revenue / costs	This indicator is the ratio of unit revenue to cost	Sustainability of cost levels/tariffs. It would reflect the price-cost-revenue collection relationship.

Indicator name	Formula	Explanation	Uses and limitations
Opex recovery	operating costs / revenue billed	The indicator of operating expenses covered by revenues is a ratio of operating costs to revenues billed, expressed as percentage.	It reflects if the utility is capable of recovering its current expenditures at the existing consumption level and tariffs. This indicator is below 100% if operational cost is covered by revenues. To be able to recover costs that include capital expenses (in addition to operating expenses) and to account for non-collection, this indicator should be noticeably below 100%.
Average Opex	Opex / cm	This is the indicator of the average OPEX costs incurred per unit of natural gas distributed	A measure of how much OPEX is incurred in distributing a unit of natural gas. Its use is relevant in the context of multivariate analysis.
	Opex / connection	The ratio of OPEX incurred to connections within the distribution network	A measure of how much OPEX is incurred per connection (ratio) within the network (i.e. it is not a reflection of the OPEX incurred by each connection). Its use is relevant in the context of multivariate analysis.
	Opex / Km	The ratio of OPEX incurred to the number of kilometres of pipeline in the distribution network	A measure of how much OPEX is incurred in the context of the length of the pipeline network. Its use is relevant in the context of multivariate analysis.
Average CAPEX	CAPEX / cm	This is the indicator of the average CAPEX costs incurred per unit of natural gas distributed	A measure of how much CAPEX is incurred in distributing a unit of natural gas. Its use is relevant in the context of multivariate analysis.
	CAPEX / connection	The ratio of CAPEX incurred to connections within the distribution network	A measure of how much CAPEX is incurred per connection (ratio) within the network (i.e. it is not a reflection of the OPEX incurred by each connection). Its use is relevant in the context of multivariate analysis.
	CAPEX / Km	The ratio of CAPEX incurred to the number of kilometres of network pipelines	A measure of how much CAPEX is incurred in the context of the length of the pipeline network. Its use is relevant in the context of multivariate analysis.

3. Task 2 - EU-wide principles for tariff regulation

3.1. Policy objectives and the role of DSOs

Traditionally the regulation of DSO activities has been focussed on the attainment of (operational) cost efficiency together with an adequate level of quality of service and service coverage. Within this framework the DSOs have to adapt the infrastructure to the needs of demand growth and are pushed to increase their (operational) efficiency through incentive measures on allowed revenues.

The gradual diffusion of new smart grid technologies and the new models and roles attributed to DSOs within the process of smartening of the grid have added new relevant objectives to the distribution activity and a new dimension and relevance to the traditional ones. DSOs are now a fundamental actor in the implementation of the “active network” and will increasingly interact with TSOs and market participants in the management of their systems.

Apart from the policy objectives traditionally linked to DSO activities, the additional policy objectives that can be identified in European and national policies in the fields of energy markets, climate policies and security of supply are:

- Encouraging energy efficiency;
- Encouraging the development of Distributed Energy Resources (DER);
- Contributing to system flexibility;
- Promoting the well-functioning of the electricity and gas markets.

These objectives will be pursued through the development and smartening of the distribution grids for which six deployment priorities have been identified by the EU TP Smart Grids. The priorities include: enabling the grid to integrate users with new requirements; enhancing efficiency in day-to-day grid operation; ensuring grid security, system control and quality of supply; better planning of future grid investment; improving market functioning and customer service; enabling and encouraging stronger and more direct involvement of consumers in their energy usage.

The accomplishment of the above mentioned objectives and deployment priorities encompasses all the aspects of the regulation of DSO activities, including:

- The relationship of DSOs with other stakeholders;
- The definition of standards for smart grid deployment;
- The regulation of the interfaces (i.e. the boundaries of asset ownership and operating activities) between the DSOs, TSOs and market participants;
- The installation and maintenance of smart metering;
- Data handling;
- Data privacy and security rules;
- The roles and responsibilities for electric vehicles (EV) connection;
- The procedures and platforms for the procurement and use of system services in the DSO networks;
- The regulation of DSOs’ tariffs in terms of allowed revenues and tariffs structure.

This last aspect constitutes the focus of the current study and is particularly relevant for the accomplishments of the core policy objectives that apply to DSO activities.

3.2. Policy objectives linked to distribution tariffs

In this chapter principles for distribution tariffs are discussed within the broader analysis of the objectives and tools available to regulators, governments and the Commission to shape the future role of the DSOs.

Based on the traditional and new role of DSOs within the process of smartening of the electricity network the following broad set of policy objectives can be identified related to distribution tariff system:

- Efficient operation of the network;
- Delivering target quality requirements at minimum cost;
- Allocating distribution costs amongst network users in a fair and efficient manner;
- Enhancing coverage of networks.
- Selecting the right set of investments to develop and enhance distribution grids;
- Coordinating the distribution network development and the deployment of smart technologies with the development of Distributed Energy Resources (DER);
- Extracting demand-side flexibility;

These last two objectives correspond to the new role attributed to DSOs with the deployment of smart grid technologies and expected penetration of DER at EU level, but all the objectives are directly or indirectly affected by the current development and smartening of distribution grids.

The new role of DSO in the current context will in fact require them to accommodate the entrance of DER by expanding network capacity and improving its reliability, on the one side, and to allow demand flexibility through grids characterized by real time information exchanges between DSOs and the TSO – as well as speeding up greater market integration and operational network security (ERGEG, 2010) on the other. Making this possible is strictly related to the comprehensive design and regulation of distribution tariffs as it will be affected by:

1. The capacity of revenue regulation to provide incentives on investment and innovation;
2. The capacity of the regulation of tariffs to promote and facilitate network user's active participation and flexibility.

3.3. Principles of tariff regulation

3.3.1. Principles

According to literature and regulatory practice, the design of tariff regulation schemes should reflect various principles related to the ability to send short term and long term signals for optimal system operation and system development as well as the sustainability of the distribution business and the protection of consumers.

Those tariff regulation principles can be grouped into three main sets:

The first set regards **System Sustainability Principles** and includes:

- ***Sufficiency*** – network tariffs should allow the full recovery of efficient network costs and a reasonable return on capital
- ***Achievability and adequacy of the regulated rate of return*** – the regulated rate of return should guarantee a return in line with the relative risk of the investments and financing conditions.
- ***Achievability of the incentive components*** – the incentive mechanism should pose achievable targets.
- ***Additivity of components*** – various tariff components must add up to give the total revenue requirement to be recovered

The second set regards **Economic Efficiency Principles** that aim to provide signals both to DSOs and network users to behave in a way that maximises social welfare in both the short and the long term. This includes:

- ***Productive efficiency*** – network services should be delivered to consumers at the lowest possible cost
    - ***Infrastructure cost efficiency:*** *tariff regulation should aim to incentivise efficient investment**;***
    - ***Operational cost efficiency:*** *tariffs regulation should aim to reduce operational (including administrative) costs**;***
    - ***Coordination*** – tariff regulation should aim to minimise the total system cost by coordinating distribution investment and operation with other stakeholder's investment decisions and operation including: transmission, generation, consumption, ancillary services.
- ***Allocative efficiency*** – tariff should incentivise the users to use the grid efficiently
    - **Peak reduction** - Network tariffs should promote peak demand management and aim to reduce infrastructure cost for peak demand
    - **Flexibility** - Tariffs should encourage system flexibility, e.g. distributed generation, demand response and energy efficiency
    - **Market promotion** - Tariffs should promote well-functioning electricity and gas markets
- ***Cost reflectiveness*** – consumers should be charged in accordance with the costs of the services they have received taking into account their contribution to peak demand and their position in the network.
- ***Promotion of innovation*** – tariff regulation should not create any barrier to DSO innovation

The third set regards **Protection Principles** in order to safeguard the interests of stakeholders:

- ***Transparency*** – the methodology and results of tariff allocations should be published and available to network participants, whose bills should clearly state each charged component
- ***Non-discrimination*** – all users that belong to a certain category and demand the same network services should be charged the same, irrespective of the end-use of electricity

- ***Equity*** – certain categories of users, like low income users, or users that are located in remote areas, are charged a tariff which is lower than the cost of the services received
- ***Simplicity*** – the methodology and results of the tariff allocations should be easy to understand and implement
- ***Predictability*** – tariffs should be based on observable variables, known by users and other interested parties, who should be able to easily forecast future charges
- ***Stability*** – tariffs methodology should be stable in order to minimize regulatory uncertainty
- ***Consistency*** – tariff regulation have to comply with the legislation in place.

3.3.2. Trade-offs between principles

The multiple objectives belonging to the three sets described above are not always compatible with one another and in many cases present clear trade-offs that the regulator should take into account when designing tariff regulation.

For instance, tariffs that satisfy the cost reflectiveness principles may not satisfy the simplicity principle as their calculation may require the use of a complex methodology that takes into account the costs caused by the position in the network and the contribution to peaks. Moreover, the cost reflectiveness principle may be in contrast with the stability principle if it requires a frequent updating of tariffs depending on network conditions and use.

With respect to the equity principle, a system may choose to implement it by introducing a social network tariff. Low-income customers may result to have a lower tariff even though they impose a cost of delivery identical or similar to high-income customers. In this case, tariffs may not be efficient but could still satisfy other system requirements such as complete cost recovery.

Similarly, there can be systems in which the cost of services delivered to certain users may be higher than other users depending on their geographical position. In such electricity systems, postage-stamp tariffs based on the principle of equity would result in a higher average tariffs for consumers in relatively low cost areas, thereby subsiding the customers in high cost areas. Such a tariff structure is inconsistent with the principle of allocative efficiency and cost reflectiveness, but could be deemed fair across the population as a whole.

Another example is given by the principle of allocative efficiency that may be in contrast with sustainability since network charges that are based on marginal costs are not expected to provide full cost recovery (due to the lumpiness of grid investments, economies of scale, reliability constraints) to DSOs. In the same way, the efficient allocation of costs may be based on the Ramsey-pricing principle, which is clearly discriminatory.

The trade-off between System Sustainability Principles and Economic Efficiency Principles may actually result to be particularly relevant in the current context where DSOs are increasingly required to invest in and operate new (smart) technologies, as analysed more in depth in Task 4,. With that respect it is important to decide the degree to which regulated firms should be required to accept the risks of investing in new technologies and the right balance between risks and incentives. If regulated firms are required to take on the risks of investing in new technologies - which typically have uncertain cost and performance profiles - one likely consequence is that those firms will require higher rates of return because investors which provide capital for such network investments will offer less-attractive conditions (as compensation for higher levels of uncertainty, compared with investments in technologies which have well-understood lifetimes and cost profiles). As a result, regulated firms will likely demand higher allowed revenues from the regulator; and this would have the effect of pushing up prices for consumers.

It is therefore the case that during periods where a major determinant of the successful development of smarter distribution networks is the ability to attract capital (at acceptable rates) for investments, the ideal point on the trade-off may lean towards sustainability and the implementation of regulatory frameworks which place less risk on regulated firms.

3.3.3. Relevant synergies

Besides the trade-offs existing between different tariff regulatory principles there are also some important synergies that have to be taken into account. One example is given by the intertwined nature of the productive efficiency, allocative efficiency and cost causality principles. The shared network in fact complicates the decision of what network to build, how to balance short term cost minimization with long term network development, which connections to enable, what quality of service to reach and how to share the common costs of the network among different users. All that, taking into account that there are individual decisions that can affect the overall cost of service and the cost supported by future customers as in the case of new connections, peak load and flexibility decisions of network users, while, on the other hand, there are general decisions that affect customers with different preferences and benefits.

The principle of productive efficiency implies the principles of infrastructure cost efficiency and operative cost efficiency. The regulation can treat them separately or together, depending on the regulatory approach. One aspect of the productive efficiency principle that is gaining relevance today is the substitution effect of OPEX and CAPEX and the coordination between them. The 'deferred investment value' of distributed generation can be defined as the value of postponing the need to reinforce the system in case of load growth or reducing the investment required in case of equipment replacement[14]. A proper coordination of network investment and DER and flexibility development can alleviate congestion and reduce the need for generation in other parts of the network. It may also change the distribution of load and power flows across the network and lower the overall level of losses in the system. It is important to take into account that the impact of distributed generation on DSO investment expenditures may be positive or negative dependent on network characteristics, type of network management operation and dynamics in the distribution network (e.g. electricity demand growth and need for asset replacement). The impact on DSO investment expenditures also varies significantly depending on where distributed generators choose to connect. In the event that most or all distributed generators choose to connect in areas where space capacity does not exist, then costs will be considerably higher than if they connect in areas where there is spare capacity.

These factors highlight the relevance of how to incentivize DSOs to engage in active distribution system management and introduce another fundamental synergy between economic efficiency principles and innovation promotion. While the form of remuneration itself results in different incentives to be cost-efficient (e.g. within an incentive-based system DSOs get to keep all the savings from cost reductions), and also in the choices among CAPEX and OPEX, the regulatory framework can also include additional elements that recognize the different risk profile and cost drivers of

[14] Cao et al., 2006; Méndez et al., 2006a; Jil & Goos, 2006

innovative technologies and operating procedures in order to stimulate their deployment by DSOs. Indeed, in a survey conducted by CEER (2011), two major barriers to the deployment of smart and active distribution systems were identified, namely first, to encourage network operators to choose the most *cost-efficient* investment solutions, and second, to encourage network operators to choose *innovative* solutions.

3.4. EU wide principles

3.4.1. Current principles present in EU legislation

The two key Directives concerning common rules for the internal market in electricity *(2009/72/EC)* and natural gas *(2009/73/EC)* provide significant flexibility to national regulatory authorities (NRAs) in the development of regulations for electricity and natural gas distribution pricing.

In particular, Article 37(1) (a) of Directive 2009/72/EC and Article 41(1)(a) of Directive 2009/73/EC state that the NRA shall have the duty of:

> "Fixing or approving, in accordance with transparent criteria, transmission or distribution tariffs or their methodologies".

In addition, Article 37(8) of Directive 2009/72/EU and Article 41(8) of Directive 2009/73/EC require NRAs to:

> "Ensure that transmission and distribution system operators are granted appropriate incentive, over both the short and long term, to increase efficiencies, foster market integration and security of supply and support the related research activities".

Provisions in Directive 2009/72/EC (Art. 25.7), moreover require that

> "When planning the development of the distribution network, energy efficiency/demand-side management measures or distributed generation that might supplant the need to upgrade or replace electricity capacity shall be considered by the distribution system operator".

Some additional restrictions on the activities of NRAs are provided by the requirement to ensure there are no cross-subsidies between different activities in the electricity and natural gas supply chain (Articles 37(1)(f) and 41(1)(f) respectively).

Furthermore, the Directive 2012/27/EU (Article 15) states that:

"Member states shall ensure the removal of those incentives in transmission and distribution tariffs that are detrimental to overall efficiency (including energy efficiency) of the generation, transmission, distribution, and supply of electricity or those that might hamper participation of demand response, in balancing markets and ancillary services".

Finally, in Annex XI of the Directive, it is stated that "network tariffs shall be cost-reflective of cost-savings in networks achieved from demand-side and demand-response measures and distributed generation, including savings from lowering the costs of delivery or of network investment and a more optimal operation of the network". It is moreover presented that "network regulation and tariffs shall not prevent network operators or energy retailers making available system services for demand response measures, demand management and distributed generation on organized electricity markets".

Reflecting the flexibility provided by the Directives, a wide variety of approaches for the pricing of distribution services has been introduced in the Member States (MS).

3.4.2. Relevant principles in the current context

In order to meet the challenges posed by the tariff regulation in the new context of active grid management and smartening of the DSOs’ grids, a balance should be found between the multiple conflicting principles described in the previous paragraphs. In particular it seems fundamental to strike a balance among the principles of sufficiency, productive efficiency, allocative efficiency, cost reflectiveness, innovation promotion, transparency, predictability, simplicity and stability. This balance depends on how NRAs weigh each of the principles within the specific regulatory context of each country, but a common basis of shared principles would facilitate the promotion of the policy objectives linked to distribution activities at the EU level.

The sufficiency requirement is a necessary condition to attract capital in the industry; we note in this respect that the merits of incentive-based mechanisms (such as price-cap or revenue-cap mechanisms) require the sufficiency requirement to be stated in a way such that it is compatible with companies occasionally obtaining less than, and more than, the baseline revenue targets. At the same time innovation promotion is fundamental to assure the implementation of the measures that are needed in order to overcome the potential barriers to innovation and production efficiency posed by innovation risks.

On the other hand, the close interdependence of the productive efficiency, allocative efficiency and cost causality principles highlights how the allocation of distribution costs should be based as far as possible on tariffs that reflect costs, including opportunity cost in case of scarcity. This is even more important now that the rollout of smart meters fosters users’ active role in the system and improves customer incentives to enable network optimisation and the necessary investments by DSOs, satisfying at the same time the non-discrimination principle.

Stability of tariffs methodology is one more relevant principle that helps minimizing regulatory uncertainty and therefore promotes investments and users active participation.

On the user protection side, it is important to assure that tariffs are transparent and therefore able to provide clear information on each cost component that helps the efficacy of the economic signals received by network users, thus also promoting competition and market functioning. Predictability of tariffs that are based on observable variables, known by users and other interested parties, further enhances users’ understanding and confidence, facilitating virtuous behaviour.

Starting from a tariff system meeting those principles, it is then possible to develop criteria to assess the merit of measures providing additional incentives to reduce peak demand and promote flexibility. The principles on the assessment of such additional measures will be developed together with the analysis of MS regulatory systems and the identification of best practices in the following chapters.

4. Task 3 - Analysis of the distribution tariffs and their methodologies or terms and conditions approved by regulatory authorities

4.1. Introduction

In this chapter we identify regularities and highlight exceptions, across Member States, on selected aspects of the organization and regulation of electricity and gas distribution. A detailed description of the regulatory schemes implemented in each Member State can be found in the Annex.

We organize the analysis around the following topics, each investigated in a section of the chapter:

- Industry structure (section 4.2)
- Revenue setting mechanism (section 4.3)
- Tariff setting mechanism (section 0)
- Network development (section 4.5)
- Flexibility measures (section 4.6)
- Metering (section 4.7)

Regulatory schemes implemented by the Member States are typically hybrid, in that they include multiple provisions sometimes with opposite effects. Therefore our characterization of the regulatory models implemented in the Member States reflects to some extent our judgement of the relative impact of alternative provisions.

4.2. Industry structure

The following tables report the number of DSO's active in each Member State, the number of large distributors and the total number of consumers connected to the distributor's network for the electricity and gas sectors.

Table 11: Electricity distribution industry structure - summary

	Number of DSOs	Number of large DSOs (>100,000 customers)	Share of total demand covered by large DSOs	Total number of consumers connected to the distribution network
AT	124	11	92%	5 870 000
BE	n/a	n/a	n/a	n/a
BG	n/a	n/a	n/a	n/a
CY	n/a	n/a	n/a	n/a
CZ	3	1	83%	5 800 000
DE	883	103	74%	49 300 000
DK	71	7	70%	3 000 000
EE	n/a	n/a	n/a	n/a
ES	342	17	95%	29 500 000
FI	81	8	20%	3 100 000
FR	81	8	20%	3 100 000

	Number of DSOs	Number of large DSOs (>100,000 customers)	Share of total demand covered by large DSOs	Total number of consumers connected to the distribution network
GB	21	14	99.5%	30 000 000
GR	1	1	100%	7 179 314
HR	1	1	100%	2 300 000
HU	6	6	100%	5 500 000
IE	1	1	100%	2 000 000
IT	151	10	97%	27 000 000
LT	6	1	100%	1 620 000
LU	5	1	90%	281 428
LV	n/a	n/a	n/a	n/a
MT	1	1	100%	285 214
NL	8	5	n/a	8 000 000
PL	169	5	91%	16 800 000
PT	13	3	99%	6 086 000
RO	8	8	100%	8 842 000
SE	8	5	52%	5 200 000
SI	1	1	100%	925 000
SK	163	3	n/a	2 400 000

Source: data provided by national regulators

Table 12: Gas distribution industry structure – summary

	Number of DSOs	Number of large DSOs (>100,000 customers)	Share of total demand covered by large DSOs	Total number of consumers connected to the distribution network
AT	20	6	n/a	1 350 000
BE	n/	n/a	n/a	n/a
BG	n/a	n/a	n/a	n/a
CY	n/a	n/a	n/a	n/a
CZ	74	6	n/a	n/a
DE	720	88	n/a	n/a
DK	3	1	90%	n/a
EE	n/a	n/a	n/a	n/a
ES	5	4	100%	7 448 827
FI	25	0	0%	75
FR	26	3	99%	11 000 000
GB	31	19	99.6%	23 329 812
GR	3	1	n/a	298 874
HR	36	1	48%	n/a
HU	10	5	99%	3 060 000
IE	1	1	100%	657 000
IT	233	30	81%	21 523 072
LT	6	1	n/a	n/a

	Number of DSOs	Number of large DSOs (>100,000 customers)	Share of total demand covered by large DSOs	Total number of consumers connected to the distribution network
LU	3	0	0%	84 277
LV	n/a	n/a	n/a	n/a
MT	n/a	n/a	n/a	n/a
NL	9	7	n/a	7 500 000
PL	35	6	95%	6 470 000
PT	11	4	88%	1 341
RO	n/a	n/a	n/a	n/a
SE	5	0	0%	37 000
SI	n/a	n/a	65%	n/a
SK	n/a	n/a	n/a	n/a

Source: data provided by national regulators

As the tables show there's a high level of heterogeneity across member States on the structure of distribution, in particular for electricity: in several countries there are more than 100 DSOs (AT, DE, ES, FR, IT, PL, SK), in others there only one company provides distribution services to all consumers (GR, HR, IE, MT, SI) or there are less than 10 distribution companies (CZ, HU, LT, NL, RO, SE).

The gas distribution sector is less heterogeneous: in most countries there are less than 50 distribution firms and only in two countries more than 100 gas distributors operate (DE, IT). A very high percentage of demand ranging from 48% to 100% in gas and from 52 to 100% in electricity is served by large system operators (i.e. those with more than 100,000 customers), even in countries with many small distributors.

Distribution companies with more than 100,000 customers are legally unbundled in all member states but MT that has obtained derogation from the requirements of Article 26 of Directive 2009/72 /EC. In most countries, distribution companies are part of groups that are also active in retailing. Exceptions are NL, where ownership unbundling was imposed[15], and SE, where ownership unbundling is mandatory both in electricity and gas. Also in GB there are some independent electricity and gas distributors.

Distribution companies with less than 100,000 customers in most member States feature just functional or accounting unbundling. In few countries, FI, SK, DK, and DE for electricity and HR, SI and LU for gas, a large share of consumers - ranging from 26% to 80% in electricity and from 35% to 100% for gas, are served by distributors that are not subject to legal unbundling.

4.3. Revenue setting mechanism

Allowed revenues for distributors are set or approved by regulators in most Member States, with the exception of ES, where allowed revenues are set by the Government.

[15] Although two DSOs in NL are still not ownership unbundled pending their appeal against the imposed unbundling.

In the following tables we assess the risk-allocation properties of the regulatory scheme implemented in each Member State for the electricity and gas sectors, based on the following basic features:

- Fixed price/revenues versus cost-reimbursement: other things equal, fixed-price or fixed revenues scheme place more risk on the distributors than cost-reimbursement schemes because the former makes the distributor's revenues independent from actual costs.
- Total revenue versus price targets: total revenue targets hedge distributors against volume risk, as they make allowed revenues independent of the number of users served and energy delivered. In case volumes reduce, tariffs are allowed to increase until the revenue target is achieved. Unit price targets are not adjusted to keep into account any divergence between actual volumes and the volumes expected when the targets were fixed.
- Actual cost versus standard cost: Schemes based on standard cost place more risk on regulated firms compared to schemes based on actual cost, as actual cost might turn out to be different from the standard levels on which allowed revenues are based.
- Frequency or price revisions: Longer time lags between tariff-reviews[16], other things equal, place more risk on the regulated firm.
- Re-openings: Provision to relax or tighten the price- or revenue-cap during the regulatory period in case of events beyond the distributor's control and which were unforeseen when tariffs were set. These provisions reduce the risk on distributors.
- Additional incentive-based compensation schemes: These are schemes targeted to specific objectives, such as: loss reduction, quality of service improvements, smart metering deployment, *etc*.

Regulatory schemes placing more risk on distributors are thought to provide superior incentives to cost minimization, in exchange for above-normal (expected) profits. Therefore, our analysis implicitly assesses the Member States positioning on the trade-off between: providing incentives to cost minimisation and allowing higher expected returns in order to account for risk placed on distributors.

[16] We use here "tariff review" in a general sense, as the moment when the revenue or price target is reset by the regulator.

Table 13: Revenue setting mechanisms for electricity distributors - summary

Country	Ex-ante vs. ex-post allowed cost		Volume risk on distributors	Actual cost vs. standard cost		Reopenings	Regulatory lag[17]	Financial incentives for quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
AT	√ Total allowed cost set at the beginning of the regulatory period, with firm specific X factor		No	√ Historic costs to set start-of-period	√ Benchmarking to assess cost differences among distributors.	√	4	No	√ X factor reduction in case assets are not used adequately	√ Smart metering (cost-reimbureme nt)
BE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
BG	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CY		√ Cost-plus, without performance incentives	No	√ Historic costs (actual costs) are included in the RAB		No	5	No	No	
CZ	√ Operating cost is subject to revenue cap system. Allowed cost set at the beginning of the regulatory period and update yearly with a X factor	√ Capital costs are subject to "cost reimbursemen t" and Return of Rate regulation	No	√ Actual OPEX incurred in the certain period of the previous regulatory period.		√ The regulatory framework may be altered during the regulatory period in case the market conditions or general economic situation	4	√	No	No

[17] Regulatory lag is the duration of the tariff period

Country	Ex-ante vs. ex-post allowed cost		Volume risk on distributors	Actual cost vs. standard cost		Reopenings	Regulatory lag[17]	Financial incentives for quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
						change significantly				
DE	√ Total allowed cost set at the beginning of the regulatory period, with firm specific X factor	√ Costs that cannot (or only marginally) be influenced by the DSO or that are highly volatile are treated as pass-through elements.	No	√ Historic costs (60%), revaluated costs (40%)	√ Benchmarking to assess cost differences among distributors. use of standard cost parameters related to the expansion of the service		5	√ Targets with premiums and penalties	√ Ex-post evaluation via benchmark, but no individual ex-post evaluation of investments	√ Research funds provided by state. Quality remuneratio ns for reduced interruptions . Non controllable costs (e.g. concession fees, cost of required smart meters) are passed through
DK	√ Total allowed revenue set at the beginning of the regulatory period, with a maximum level of return on capital		√	√ Historical revenues	√ DSOs are benchmarked against each other on depreciations, operating costs, and quality of supply	10+	1	√ (penalties)	No	
EE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ES	√ Total allowed		No		√ Allowed CAPEX is	No	1	√ (Targets,	No	√ Metering,

Country	Ex-ante vs. ex-post allowed cost		Volume risk on distributors	Actual cost vs. standard cost		Reopenings	Regulatory lag[17]	Financial incentives for quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
	costs are assessed annually, and tariffs are reviewed every three months. Revenue cap with efficiency adjustments				based on a comparison of unit investment costs plus incentives to reduce investment costs			Premiums and penalties)		assessed separately (as standard costs)
FI	√ Efficient investment included in the RAB and reconciliation mechanisms are used to ensure that actual revenues are in-line with allowed revenues		No	√ Actual costs (of efficient investments) are included in the RAB and reconciliation mechanisms are used to ensure that actual revenues are in-line with allowed revenues		No	4	√ Targets. Premiums and penalties up to +/- 20% of the annual rate of return	No	
FR	√ Productivity factor is applied on some predefined controllable OPEX	√ Non controllable OPEXs and Capital charges only	No	√			4	√ (targets with premium and penalties)	No	√ Smart meter (extra – remuneratio n for good performance in terms of costs, deadlines and quality of service)
GR		√ CAPEX and	No	√		No	1	No	No	

Country	Ex-ante vs. ex-post allowed cost		Volume risk on distributors	Actual cost vs. standard cost		Reopenings	Regulatory lag[17]	Financial incentives for quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
HR		OPEX costs are reimbursed under a cost-plus approach (they are updated annually)		Actual costs are used in the RAB						
		√ Rate of return (cost of service) regulatory approach. The Allowed Revenue comprises planned CAPEX and OPEX for the next regulatory period	√	√ Historic costs to set start-of-period			1	No	No	No
HU	√ Total Allowed revenues set at the beginning of the regulatory period with a maximum level of return on capital and update yearly with a X factor		No To determine next year's (T) tariffs, justified revenues are divided with T-2 year's quantities.	√ OPEX are assessed in details once in every 4 years. Costs are indexed with inflation-X yearly.	√ Benchmarking to assess cost differences among distributors. The DSO better than the average receives only its own costs, the DSO doing worse receives only the average	No	4	√ Penalty system to ensure quality standards	No	No
IE	√ Total allowed		No	√ replacement cost	√ Benchmarking to		5	√ Targets with	√ Investments	No

Country	Ex-ante vs. ex-post allowed cost		Volume risk on distributors	Actual cost vs. standard cost		Reopenings	Regulatory lag[17]	Financial incentives for quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
	revenue set at the beginning of the regulatory period			(acquisition cost, indexed with inflation)	assess cost differences among distributors.			premiums and penalties	can be excluded from the RAB in case of a negative judgment	
IT	√ Hybrid system, price cap applies on OPEX	√ Hybrid system, cost reimbursemen t on CAPEX	No	√ Assets within the RAB are evaluated on the basis of a 'historical revaluated cost' approach. Every year the value of the DSOs' assets are updated by the inflation index of the price of "investment goods"		No	CAPEX costs are revised every 1 year; the tariff component related to OPEX is reset every 4 years	Yes	√ Assessments take place for all input-based incentives different from smart grids that are not subject to ex-ante evaluation.	Only losses compensatio n is calculated separately from the distribution revenue constraint.
LT	√ 50/50 price/revenue cap model		√ DSOs bear 50% of the volume risk through volume adjustment factor	√ Historic costs to set start-of-period (For the new regulatory period 2015-2019 RAB would be based on LRAIC model, taking into account optimal network structure - benchmark- and reasonable cost value)	√ CAPEX subject to benchmarking and special analysis; international benchmarking may be considered also for OPEX		5	√ Penalties	No	No
LU	√ Some CAPEX and controllable OPEX subject to revenue cap (and	√ Some CAPEX and non-controllable OPEX are	NO	√ historic or re-evaluated cost, book value			4	No	No	No

Country	Ex-ante vs. ex-post allowed cost		Volume risk on distributors	Actual cost vs. standard cost		Reopenings	Regulatory lag[17]	Financial incentives for quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
	updated according to a pre-defined formula)	subject to cost reimbursemen t								
LV	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
MT		√ DSO estimates the actual distribution costs, according to the approved methodologies , and the regulator fixes and approves the final tariffs	No	√ The regulator focus on the cost estimates provided by the DSO based on the assumptions that the DSO will have to satisfy all the reasonable demands for service		No	Not fixed	No	No	No
NL	√ Price cap with firm specific X factors based on benchmarking of total costs		√ Revenue comes mainly from capacity tariff components	√ Actual revenues (or costs) to set start-of-period	√ Estimated industry-average costs at end of period (yardstick) based on benchmark, with X factors closing gap during period	√	3	√	√ Via benchmarking of total costs at the start of the regulatory period	No
PL	√ Revenue cap (with efficiency adjustments on OPEX via RPI-X method)		√		√ Total expenditure benchmarking	No	4	No	√ An ex-post assessment of "usefulness" is carried out but it does not affects RAB	√ Metering, assessed separately (by higher WACC than "usual" grid investments)

Country	Ex-ante vs. ex-post allowed cost		Volume risk on distributors	Actual cost vs. standard cost		Reopenings	Regulatory lag[17]	Financial incentives for quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
PT	√ Operating cost is subject to price cap system. Allowed cost set at the beginning of the regulatory period and update yearly with a X factor	√ Capital costs are subject to "cost reimbursement" and Return of Rate regulation	Partly Shared between DSO and consumers	√ OPEX is defined in the first year of regulatory period and updated both with IPIB-X and the evolution of the cost drivers set		No	3	√	No	√ Investments in innovation have a remuneration premium and the x factor in OPEX
RO	√ Price CAP model, with X factor		No	√ RAB value set in 2004, at the moment of implementing the incentive based regulation. This value is actualized with consumer price index. New investments enter with initial book value.		√, There are corrections mainly due to volumes variation, cost of electricity losses and non-controllable costs.	5	√	No	√ Reduction of distribution network losses. Between 50% and 75% of losses efficiency gain are transferred to customers, the rest to the DSO.
SE	√ Price-cap on controllable OPEX	√ Cost-plus on CAPEX and non-controllable OPEX.	Yes	√ Actual costs for CAPEX and non-controllable OPEX. Planned investments in the forthcoming regulatory	√ Standardised costs only to the extent that an efficiency factor is used to estimate controllable OPEX at	No	4	Yes Costs of interruptions for customers are included	No	No

Country	Ex-ante vs. ex-post allowed cost		Volume risk on distributors	Actual cost vs. standard cost		Reopenings	Regulatory lag[17]	Financial incentives for quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
				period are included within the RAB. Four methods can be used to value assets to be rolled into the RAB: standard values, acquisition value, book value and valuation by other way. The methods are used in descending order.	the end of the period			in regulation as measure of quality. Actual interruptions costs are compared to reference level annually. Revenue cap is adjusted for deviations		
SI	√ Total allowed cost set at the beginning of the regulatory period, with firm specific X factor		No	√ Book value	√ Benchmarking to assess O&M cost differences among distributors.	√	3	√ Targets with premiums and penalties	No	√ Smart meters (A one-off additional 2% yield in the year of activation of the assets applies for the Smart Grid projects of a total value exceeding € 200,000.)
SK	√ Price CAP model		Yes	√ Input value RAB is based on the performed DSO		√ Prices be adjusted in	5	√	√ The price formula	No

Country	Ex-ante vs. ex-post allowed cost		Volume risk on distributors	Actual cost vs. standard cost		Reopenings	Regulatory lag[17]		Financial incentives for quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*				
				asset assessment in 2006. The RAB value for 2012 takes into account CAPEX development in the given period and the value of depreciation. During the regulatory period the RAB value does not vary		some specific circumstances				includes a parameter by which NRA checks the amount of investment realized. The amount of CAPEX is checked in the first place as necessary to perform the regulated activity.	
GB	√ Revenues are set every 8 years as part of a price control process. Penalties or rewards from incentive schemes automatically update these revenues (on a 2 year lag).		No	√ In determining the revenue requirement the toolkit approach used also makes use of historical and network company forecast data.	√ Standard costs are calculated using a combination of aggregated and disaggregated econometric and engineering based approaches, TOTEX and disaggregated data	√	8		√ Incentive adjustments in the allowed revenue formula for quality of service	No	√ Incentive adjustments in the allowed revenue formula for distribution losses performance, performance in relation to Transmission Connection Point Charges, innovation

Country	Ex-ante vs. ex-post allowed cost		Volume risk on distributors	Actual cost vs. standard cost		Reopenings	Regulatory lag[17]	Financial incentives for quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
										funding performance, and performance in relation to Distributed Generation

Table 14: Revenue setting mechanisms for gas distributors - summary

Country	Ex-ante vs ex-post allowed cost		Volume risk on distributors	Actual cost vs standard cost		Reopenings	Regulatory lag	Financial incentives for Quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
AT	√ Total allowed cost set at the beginning of the regulatory period, with firm specific X factors based on benchmarking of total costs		No	√ Historic costs to set start-of-period	√ Benchmarking to assess cost differences among distributors; gaps between standard and costs narrowed by X factors.	√	5	No Now inactive, but formula included in the revenue calculation mechanisms	√ Via benchmarking of total costs at the start of the regulatory period.	
BE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Country	Ex-ante vs ex-post allowed cost		Volume risk on distributors	Actual cost vs standard cost		Reopenings	Regulatory lag	Financial incentives for Quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
BG	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CY	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CZ	√ Operating cost is subject to revenue cap system. Allowed cost set at the beginning of the regulatory period and update yearly with a X factor	√ Capital costs are subject to “cost reimbursement” and Return of Rate regulation	No	√ Actual OPEX incurred in the certain period of the previous regulatory period. The current RAB is based on this revaluated (based on replacement values) book value of assets and is not further indexed.		√ Legislation allows reassessing determined parameters for regulatory period or regulatory year only in exceptional cases (e.g. supply security disruption).	5	No	No	No
DE	√ Total allowed cost set at the beginning of the regulatory period, with firm specific X factor	√ Costs that cannot (or only marginally) be influenced by the DSO or that are highly volatile are treated as pass-through elements.	No	√ Historic costs (60%), revaluated costs (40%)	√ Benchmarking to assess cost differences among distributors; use of standard cost parameters related to the expansion of the service		5	No	√ Through the TOTEX benchmarking	√ Research funds provided by state. Quality remuneration s for reduced interruptions. Non controllable costs (e.g. concession fees, cost of smart meters) are passed

Country	Ex-ante vs ex-post allowed cost		Volume risk on distributors	Actual cost vs standard cost		Reopenings	Regulatory lag	Financial incentives for Quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
										through.
DK	√ Allowed revenues set at the beginning of the regulatory period		No	√ Book value	√ Benchmarking of operating costs (unit cost model)		4	No	No	No
EE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ES	√ Total allowed cost set in 2002 and updated every year based on inflation (up to 2014), volumes and number of connections		√		√ Same per connection and per cm cost allowed for all distributors		Ministry's discretion	√ Penalties for service interruptions	No	
FI		√	No	√ Actual costs, with no benchmarking			4	No	A partial ex-post assessment is carried out, but not published	No
FR	√ Allowed revenues set at the beginning of the regulatory period, productivity factor on the OPEX and output based incentive regulation	√ For some costs components (i.e. capital charges).	No DSOs are hedged with climatic risk. However, they bear the risk of loss of customers.	√	No Benchmarking is for information purpose only. It contributes to the definition of the productivity factor.	√	4	√ Bonus/penalties applied depending on predefined targets	No Assessment of investment efficiency only (not usefulness) through the analysis of unit costs	√ For smart meter project (in case of good performance in terms of costs, deadlines and quality of service)

Country	Ex-ante vs ex-post allowed cost		Volume risk on distributors	Actual cost vs standard cost		Reopenings	Regulatory lag	Financial incentives for Quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
GR	√ Total allowed revenues are set		No		√ Each DSO forecasts its allowed revenues based on planned investments and its own ´business model´	n/a	No fixed period	No	No	No
HR	√ Allowed revenue is set for regulatory period based on planned CAPEX and OPEX	√ Ex-post adjustment based on real values for CAPEX	No	√ Net book value	√ Benchmarking of operating costs		3 since 2014, 5 since 2017	√ Revenue formula	√ In 2017	√ Cost reimburseme nt for services provided outside of the guaranteed standards
HU		√ Regulatory model is based on cost reimbursement	No		√ DSO costs with more than 100.000 customers are compared to each other in benchmark process	√ Legislation allows an extraordinary tariff revision which is used to compensate for big unexpected changes in the market environment.	4	No	No	No
IE	√ Allowed revenues set at the beginning of the regulatory period	√ For some costs components	No	√ Replacement value and updated to consider inflation	√ Benchmarking to assess cost differences among distributors		5	No	No	No
IT	√ Hybrid system, partly price-cap (OPEX)	√ Hybrid system, partly cost reimbursement / cost of service (CAPEX)	No		√ OPEX are defined on the basis of a parametric approach. The values are differentiated on the basis of the size of DisCos and		6	√ Premium/ penalties for service intervention speed, gas	√	√ Metering capital and opex

Country	Ex-ante vs ex-post allowed cost		Volume risk on distributors	Actual cost vs standard cost		Reopenings	Regulatory lag	Financial incentives for Quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
					density of final customers (delivery points / meter). Centralized assets are defined using a parametric approach. New investments related to electronic meters are evaluated on the basis of a mix of actual costs and standard costs.			leaks numbers, incidents and emergencies, continuity of supply, commercial quality		
LT	√ Allowed revenues set at the beginning of the regulatory period		No	√ Historic costs to set start-of-period	√ CAPEX subject to benchmarking and special analysis; international benchmarking may be considered also for OPEX		5	√ Targets with premiums and penalties	√	No
LU	√ Some CAPEX and controllable OPEX subject to revenue cap (and updated according to a pre-defined formula)	√ Some CAPEX and non-controllable OPEX are subject to cost reimbursement	No Tariffs are updated on a yearly basis	√ Historic or re-evaluated cost, book value			4	No	No	No
LV	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
MT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
NL	√ Price cap with firm specific x factors based on benchmarking of total costs		√ Revenue comes mainly from capacity tariff components	√ Actual revenues (or costs) to set start-of-period	Estimated industry-average costs at end of period (yardstick) based on benchmark, with X factors closing gap during period	√	3	No	√ Via benchmarking of total costs at the start of the regulatory period	No

Country	Ex-ante vs ex-post allowed cost		Volume risk on distributors	Actual cost vs standard cost		Reopenings	Regulatory lag	Financial incentives for Quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
PL	√ Hybrid system, partly revenue-cap (OPEX)	√ Hybrid system, partly cost-reimbursement (CAPEX)	√ However, DSOs can apply for an ex post correction if planned and real revenues do not align	√ Actual costs used, total expenditure. No benchmarking applied		√ DSOs may request a reopening	1	No	√	No
PT	√ Operating cost is subject to price cap system. Allowed cost set at the beginning of the regulatory period and update yearly with a X factor	√ Capital costs are subject to “cost reimbursement” and Return of Rate regulation	No	√ OPEX is defined in the first year of regulatory period and updated with IPIB-X factor Capital costs are assessed every year. There are ex-post real values adjustments.		No	3	No	No	
RO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
SE	√ Price-cap on controllable OPEX	√ Cost-plus on CAPEX and non-controllable OPEX.	√	√ Actual costs for CAPEX and non-controllable OPEX. Planned investments in the forthcoming regulatory period are included within the RAB. Four methods can be used to value assets to be rolled into the RAB: standard values, acquisition value, book value and valuation by other way. The methods are used in descending order.	√ Standardised costs only to the extent that an efficiency factor is used to estimate controllable OPEX at the end of the period	No	4	No	No	No

Country	Ex-ante vs ex-post allowed cost		Volume risk on distributors	Actual cost vs standard cost		Reopenings	Regulatory lag	Financial incentives for Quality of service	Ex post assessment of investment usefulness	Other Ad-hoc schemes
	Fixed price/revenues	*Cost of service*		*Actual cost*	*Standard cost*	*Allowed*	*Years*			
SI	√ Total allowed cost set at the beginning of the regulatory period, with firm specific X factor		No	√ Book value	√ Benchmarking to assess O&M cost differences among distributors.		3	No	No	No
SK	√ Price CAP model		Yes	√ Input value RAB is based on the performed DSO asset assessment in 2006. The RAB value for 2012 takes into account CAPEX development in the given period and the value of depreciation. During the regulatory period the RAB value does not vary		√ Tariff prices could be adjusted in some specific circumstances	5	No	No	
GB	√ Revenues are set every 8 years as part of a price control process. Penalties or rewards from incentive schemes automatically update these revenues (on a 2 year lag).		No, over- or under-recovery of revenues is corrected in the following allowed revenue formula	√ In determining the revenue requirement the toolkit approach used also makes use of historical and network company forecast data.	√ Standard costs are calculated using a combination of aggregated and disaggregated econometric and engineering based approaches, TOTEX and disaggregated data	√	8	√	No	

As the tables show, mechanisms based on pre-determining the distributor's allowed revenues for a certain regulatory period – typically 4 or 5 years[18] - are implemented in most member States for electricity; yearly rate revisions are implemented only in HR, DK, ES, MT[19], GR. For gas, only PL sets tariff every year.

In several countries cost benchmarking is used to assess allowed distribution revenues; in electricity, AT, ES, FR, DE, LT, GB, PL, NL, HU benchmark total distribution costs, while DK, IE, SI and SE benchmark only operating costs. In some cases, in particular AT, SE and NL, cost departures from benchmark level (may[20]) result in higher X factors, rather than below-cost initial allowed revenues, in order to ensure that allowed revenues gradually convergence to efficient costs. Benchmarking in gas is also frequently implemented, although capital costs are typically subject to a cost reimbursement regime, except in GB, NL and DE where total cost benchmarking is applied.

Approaches based on pre-determined allowed revenues, as opposed to mechanisms ensuring recovery of actual costs, are typically motivated as a way to incentivize distributors to minimize cost during the regulatory period. However, multiple provisions are implemented in order to mitigate the risk of unintended profits or losses for distributors resulting from unanticipated dynamics of demand or cost. First, in most Member States tariff adjustments during the regulatory period are allowed in order to hedge distributors for volume risk, i.e. from the risk that demand for distribution services turn out to be lower or higher than the level assumed when the tariff parameters are set. In gas, for example, only ES, SK, and to a limited extent NL, leave distributors with volume risk.

Second, tariff structures that place more weight on fixed or capacity-related components tend to reduce the volume risk, to the extent that energy consumptions are more volatile than capacity commitments and the number of connections. In NL, for example, gas and electricity distribution costs are recovered almost entirely through capacity-dependent charges.

Third, in most countries the revenue setting process is forward looking; in particular allowed revenues reflects investment that are expected to be carried out during the regulatory period. In some cases investments foreseen at the tariff setting stage are checked ex-post against actual investments and the cost of extra or under-investment is offset in the next tariff setting round.

Fourth, in some countries only the share of revenues corresponding to operating costs is fixed ex-ante, while the share corresponding to investment cost is updated annually to reflect actually incurred expenditures, and so are tariffs. This holds for electricity in AT, DE[21], LU, GR, IT, SE, CZ, PT and, for gas, in AT, HR, LU, CZ, HU, PT, FI, IT, PL, SE. In FR, both operating and investment costs which are considered to be uncontrollable by the DSO are included in the expense and income claw-back account mechanism,

Fifth, *ad hoc* revenue assessment methodologies are implemented for selected activities whose costs are possibly more difficult to predict and/or whose technological, industrial and financial

[18] GB implements a 8 year regulatory period.
[19] In MT the review takes place when at the distributor's call.
[20] In NL the NRA decides upon cost departures based on the specific circumstances.
[21] In DE electricity distributors can apply for cost-based revenue assessment in the case of major expansion investments at the 110-kV level.

dimensions are exceptional compared to others investments. – in particular, those related to smart meter deployment, like in DE and IT.[22]

Sixth, when cost benchmarking is implemented, firms with higher than average costs can request that their own cost be individually analyzed in order to assess the impact on cost of special circumstances that may not have been adequately kept into account in the benchmarking exercise.

Seventh, allowed revenue revisions during the regulatory period at the distributor's request (so called "re-openings") are carried out if exceptional and unforeseen events cause actual costs or revenues materially depart from those expected when allowed revenues were set.

A potentially large source of risk for distributors is that investments that were sunk based on certain expectations turn out to be less useful than expected, in particular in case actual demand is lower than expected when the investment was decided.[23] We notice in this respect that only IE in electricity and HR, LT, and PL in gas provide for an explicit ex-post assessment of usefulness of distribution investment in the context of the allowed revenue setting process. However, an implicit ex-post assessment of usefulness of investments is carried out in those Member States that base allowed revenues or X factors on total cost benchmarking. In that case a distributor might not be able to cover the cost of useless investment that other distributors did not make, to the extent that the cost of the useless investment will not impact (or will impact only marginally) on the standard cost assessed by the regulator.

In most countries, economic incentives to deliver target levels of quality of service are implemented. No quality related incentives are implemented in AT, HR, LU, CY, GR, PL, MT.

The revenue setting mechanisms implemented in most countries, both for electricity and gas, appear to place moderate risk on distributors, in particular in terms of under or over remuneration of invested capital. More robust incentives to reduce operating cost, and therefore more risk on distributors, are implemented in most countries.

4.4. Tariffs

In most Member States tariffs are set by the national regulator. However in some countries the responsibilities are shared between the regulator and the DSO, the NRA mainly defines the rules and approves the tariff proposed by the DSO. ES is the only country where the Government sets the tariffs.

Distribution tariffs are published in all member States. However, ES distribution tariffs are bundled with other tariff components, covering costs such as renewable generation subsidization. In GR only total gas retail tariffs are published.

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[22] In FR, for gas and electricity, the *ad hoc* revenue settlement for smart meters is not motivated by the fact that costs are possibly more difficult to predict, but rather for incentive purposes, explained by the fact that the technological, industrial and financial dimensions of the project are exceptional compared to other investments.

[23] It can be noted that sunk investments based on expectation which turn out to be less useful than expected are also a source of risk for the customer base whom fund the assets. Hence it may be appropriate that this risk is shared between the DSO and customers. Ex-post reviews may generate regulatory uncertainty for DSOs and could therefore lead to less investments being made than if the DSOs are allowed to assess the risks themselves.

The following tables report, for each Member State, information on the main features of distribution tariffs and connection charges for the electricity and gas sectors. In particular we consider:

- The cost-reflectiveness criterion implemented in setting distribution tariffs
- The split of distribution tariffs in components that reflect different DSOs' activities, like power transportation, metering and commercial activities.
- The tariff structure, including the base to assess tariff components (e.g. energy consumption, maximum power withdrawal, etc.), time-of-use tariffs and geographical differentiation.
- Structure of connection charges (deep or shallow)
- Social tariffs
- The breakdown of distribution cost among consumer's types: we report the share of distribution costs allocated to the different types of consumers.

Table 15: Electricity, distribution tariffs and connection charges

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Domestic/small bus./large bus
AT	√ Based on connection voltage (cascading), energy and capacity	√ Network, metering, commercial	• Power • Energy • Fixed	√ Only for large consumers	√ Only for HV consumers	Deep	No/No	7%/24%/69%
BE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
BG	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CY	√ Based on connection charge (varies depending on customer class) and an energy use charge	Information not available	• Fixed charge based on total energy consumption (€/bi-monthly) • Energy	√ Yes for domestic, commercial and industrial customers. Not for public light or water pumping customers	√	Generally, they are shallow. In exceptional cases, they are deep	No/No	37%/43%/20%
CZ	Based on connection voltage (cascading), energy and capacity	No	• Monthly max withdrawal power • Energy	√	Not geographically-uniform	• Shallow. A Fee for connection is defined according voltage level and type of connection • Fee covers half of the average connection cost	No/No	42%/29%/29%

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Domestic/small bus./large bus
DE	√ Based on connection voltage (postage stamps), operating hours, energy and capacity	√ Network usage, metering, metering point operation and billing	• Power • Energy • Fixed (per year)	No Only atypical customers	No Each DSO sets different tariffs	Deep	No/No	n/a
DK	√ Based on connection voltage and energy	No	• Subscription • Energy	√ Only for large consumers	No Each DSO sets different tariffs	Shallow	No/No	n/a
EE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ES	√ Based on connection voltage, energy and capacity	√ Network, commercial	• Monthly max withdrawal • Energy	√ All but smallest consumers	√	Shallow Standard for smaller consumers	Yes/No Implemented via retailers	52%/23%/25%
FI	√ Based on connection voltage, energy and capacity	n/a	• Energy • Maximum withdrawal capacity • Fixed / per customer charge	√	No	Both types. Shallow charges for small consumers and small embedded generators. Deep charges for larger consumers and generators	No/No	Information not publicly-available
FR	√ Based on connection voltage, duration of usage	√ Withdrawal, metering , administrative	• Power • Energy • Fixed	√ Withdrawal components	√	Shallow for residential consumers and deep for	Yes/No Implemented via retailers	68%/14%/18% LV<36kVA/LV>36kVA/HV

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Domestic/small bus./large bus
	(rate of use of the grid) and capacity	management				generators		
GR	√ Based on connection voltage and energy	n/a	• Capacity charge • Energy	√	√	Deep for embedded generators and isolated consumers; partially-deep for all other consumers	Yes/Yes	53%/38%/9%
HR	No Depending on the customer category and the tariff model	No	• Meter • Active power (MV and LV >30 kW) • Active energy • Excess reactive energy (only non-residential customers)	√ two different components in peak and off-peak times	√	Deep	No/No	47%/38%/15%
HU	Based on voltage level and energy	Network cost Distribution losses	• Monthly max withdrawal power • Fixed • Energy	No	√	Shallow for Small Customers at LV	No/No	n/a
IE	No Capital and operating costs are allocated across different system levels and then divided by the number of	No	• Energy • Fixed (annual) • Power (only business customer and auto producers)	√ Day/night tariff	No Urban and rural tariff for domestic customers	Shallow for small connections	No/No	n/a

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Domestic/small bus./large bus
	customers in each level							
IT	√ Based on capacity, voltage levels and energy	Distribution, metering and commercial services.	• Energy • Capacity • Fixed, per customer charge	No	√	Shallow charges: consumers and embedded generators. HV network users - mainly- shallow approach, with deeper charges	Yes (it is a subsidy mechanism) /Yes (via both the distributor and retailers)	n/a
LT	√ Based on connection voltage, power and energy	No	• Power • Energy	√ One time zone tariff and two time zone tariff	√	Deep	No/No	33%/26%/41% Residential/commercial <400kw/commercial >=400kw
LU	√ Based on connection voltage	No	• Actual peak demand over the year • Energy	No	No Each DSO sets different tariffs	Shallow for small customers, deep for larger customers	No/No	34%/66% Residential/industrial
LV	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
MT	n/a	n/a	• Monthly max withdrawal power • Fixed • Energy	√ Only non-residential (day/night)	√	• Both types. • Deep charges for consumers and generators for Connection	No/No Although presence of energy vouchers	n/a

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Domestic/small bus./large bus
						ratings above 60A, the others shallow		
NL	√ Based on capacity and energy	Distribution and connection, metering	• Contracted kW • Peak kW • Energy • Capacity (for small customers)	No	√ Only metering tariffs for small consumers are uniform. For other tariffs the calculation method is the same but the actual tariff may be different	Shallow	No/No	51% / 18% / 31%
PL	√ Based on capacity and energy		• Energy • Transition fee (charge resulting from termination of PPAs) • Per end-user subscription fee	√	No	Shallow	No/No	39% / 30% / 31%
PT	√ Based on connection voltage level, contracted power and average power in peak hours	No	• Monthly max withdrawal power • Fixed • Energy	√	√	Deep for consumers and generators	Yes/No Implemented via suppliers	73%/10%/17%
RO	√ Based on connection voltage	n/a	• Energy	No	No	• Both types. • Shallow For small	No/No	n/a

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Domestic/small bus./large bus
	(cascading), and energy					generators/consumers • Deep For large generators		
SE	√ Based on capacity and energy	Each DSO can use any methodology they prefer as long as it is non-discriminatory and objective	DSOs can use any structure they wish provided that it is non-discriminatory and objective	√ Used by some DSOs, but not others	No	Deep	No/No	Information is not available
SI	√ Based on connection voltage, use of the network, energy (gross method)	NO	• Power • Energy	√ Summer/winter	√	Shallow	No/No	52%/32%/16% Residential/other LV/MV
SK	√ Based on connection voltage	Network cost Distribution losses	• Monthly max withdrawal • Energy • Losses	√ Depending on DSO	No	Deep	No/No	35%/27%/38%
GB	√ Based on connection voltage (cascading), energy and capacity		• Energy • Daily fixed charge • Daily capacity charge • Reactive charge • Exceeded capacity charge	√	No	Deep	No/No	Domestic: 51% Small non-HH: 12% Medium non-HH: 6% HH: 31%

Table 16: Gas, distribution tariffs and connection charges

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Large/small
AT	√ Based on connection level, energy (30%) and capacity (70%)	√ Use of system, metering, other services	• Capacity charge (not for small consumers) • Energy charge	√ Only for very large consumers	NO 9 price areas	Deep	NO/NO	14%/86% Based on network level of connection
BE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
BG	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CY	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CZ	Based partially on capacity and commodity for each category of consumers. In each category there are subcategories or bands of consumption.	No	• Capacity charge • Energy charge	No	No Each DSO charges different tariff in each zone	Not used	No/No	46%/18%/36%
DE	√ Energy (30%) and capacity (70%)	√ Network usage, metering, metering point operation and billing	Standard load profile: • Fixed monthly fee • Energy charge Load	No	No 728 gas DSOs, each one charges different tariffs	Deep	No/No	n/a

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Large/small
			metered: • Capacity charge • Energy charge					
DK	n/a	No	• Energy charge	No	No 3 DSOs charges different tariffs	Mostly Shallow for consumers and embedded generators	No/No	n/a
EE	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
ES		√ Network, ancillary services (metering, intersections)	• Contractual capacity (a Fixed charge for small consumers) • Energy	No	√	Shallow Fixed price for smaller consumers	No/No	This information is not published by the Spanish NRA
FI	√ Based on energy and capacity, but exact split between each is set by individual DSOs	√ As each DSO is free to design its tariffs, the splits of tariffs between different activities varies (and is not published)	Generally includes contractual capacity and energy consumed, but varies between different DSOs (who set their own tariff structures)	No	No	Shallow	No/No	This information is not published by the Finnish NRA
FR	√ Based on yearly gas consumption	No	• Fixed monthly fee • Capacity charge	No	NO 26 DSOs charges different tariffs (GRDF represents	Shallow	Yes/No Via the retail tariff	n/a

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Large/small
			• Energy charge		96%)			
GR	√ Based on energy and capacity. Distribution tariffs are bundled with supply tariffs.	√ Bundled into a single tariff, which is also bundled with a supply tariff	Not specified; DSOs are free to implement their own structures (not published)	No	No	Shallow	No	Not published by the Greek NRA.
HR	√ Based on yearly gas consumption	No	• Energy charge • Fixed monthly fee	No	No 36 DSOs with different energy charges	Mostly shallow. Deep if special investment required	No/No System for support to vulnerable customers is currently being created on the state level.	71%/29%
HU	√ Based in consumption categories. Fixed cost are divided by the corresponding quantities and variable costs are divided by the day degree corrected volumes	No	• Fixed charge • Capacity charge (Just consumers with a gas meter size above 100m3) • Energy charge	√ Reduced capacity fee for consumers who have consumption in the summer period but do not consume in winter	No There is a regional pricing	Shallow For small and medium sized consumers	No/No	51%/20%/29%
IE	√ Based on volume ranges and 80:20 Capacity: Commodity split	No	• Capacity charges (based on expected peak day withdrawal) • Energy	No	√ Tariffs are postulated	Shallow and Deep	No/No	n/a

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Large/small
IT	√ Energy	√ Network costs, metering, commercial service costs	Fixed component and variable (energy) component (variable component depends on consumption class)	No	Tariff areas	Shallow	Yes (it is a subsidy mechanism)/Yes	Not published by the Italian NRA.
LT	n/a	No	• Energy charge	No	No 6 DSOs charges different tariffs	Mostly deep	No/No	32%/30%/38% Residential/ Commercial <10.5 GWh/ Commercial >= 10.5 GWh
LU	√ Based on pressure level	No	• Capacity charge • Energy charge	No	No 3 DSOs with different tariffs	Shallow for small consumers. Deep for larger consumers	No/No	n/a
LV	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
MT	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
NL	√ Based on energy and connection capacity	√ Distribution and connection, metering	• Administrative cost • Transport-related capacity • Connection cost • Metering	No	√ Only metering tariffs for small consumers are uniform. For other tariffs the calculation method is the same but the actual tariff may	Shallow	No	13% / 87% Based on connection capacity differentiation

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Large/small
					be different			
PL	√ Based on capacity of connection and energy	No	• Hourly capacity • Energy	No	No	Deep	No	Not published by the Polish NRA
PT	√ Based on determination of long run average incremental costs for the MP network and for the LP network. These incremental costs are further differentiated by: (i) incremental cost of used capacity; (ii) incremental cost of energy in peak periods; (iii) incremental cost of energy in off-peak periods; (iv) incremental cost per client, connected to the peripheral section, and (v) incremental cost per customer, associated with	No	• Fixed charge • Capacity charge • Energy charge	√ Two periods: off-peak (August) and peak (rest of the year)	√	Deep	Yes/Yes Discount is given on the price contracted	54%/22%/24%

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Large/small
	measuring, reading and data processing.							
RO	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
SE	√ DSOs can use any methodology they like provided it is non-discriminatory and objective.	√ Differentiation is not explicitly required. DSOs have freedom to use their preferred approach	DSOs can use any methodology they like provided it is non-discriminatory and objective.	Some DSOs use ToU tariffs	No	Deep	No/No	Not published by the Swedish NRA
SI	√ Based on annual consumption	√ Metering	• Flat rate(fixed monthly) • Power (only large consumers) • Capacity (only large consumers) • Energy	No	No 16 DSOs, with different tariffs	Shallow	No/No	n/a
SK	√ Based in capacity component and other variables (actual usage of cost center by the sale group - e.g. number of customers, gas volumes sold, gas	No	• Fixed charge • Capacity charge • Energy charge	No	√	n/a	No/No	69%/7%/24%

Country	Cost reflectiveness	Tariff splitting for different DSO activities	Tariff structure	Time of use tariffs	Geographical uniformity	Connection charges	Social tariffs implemented/via the distributor?	Share of distribution costs on consumer classes
								Large/small
	daily maximum) of each sales group. The legislation rules set the forbiddance of the cross donations of the sale groups.							
GB	√ Energy and capacity (No typical customer category capacity definitions).	√ Distribution system use, metering	• System charges • Customer charges	No	No	Deep	No/No	Not published

As the tables show, in all member States distribution costs are allocated to classes of consumers based on some cost-reflectivity criterion. Cost cascading is typically implemented, implying that consumers connected at a certain network level – typically associated with connection voltage or pressure – are not allocated costs of the network levels downstream of their connection level.

The splitting across consumers connected at the same voltage level of the share of total cost allocated to that level is generally based on energy consumption and maximum power withdrawal (or contractually committed capacity). Greater detail on the energy/capacity allocation of costs is provided in section 0 (task 5).

The structure of distribution tariffs is generally characterized by:

- A component based on the consumers energy withdrawal,
- A component based on the consumers committed capacity, i.e. on the consumer's peak withdrawal over a certain time period (monthly of yearly); for smaller consumers contractual maximum available capacity is commonly used as charging basis, instead of actual peak withdrawal,
- A fixed component, typically intended to cover metering or administrative costs.

Time of use distribution tariffs are implemented for electricity in several countries, typically for non-residential consumers and with daily (night/day) or seasonal (winter/summer) structure. Time of use gas distribution tariffs are not common.

Nationwide, uniform tariffs are implemented for electricity in HR, FR, LT, SI, ES, HU, MT, PT, CY, GR, IT and for gas in ES, PT, SK. In the other countries tariffs are differentiated by Distribution Company or by tariff zones larger than the areas covered by individual distributors. In NL only metering tariffs for small users are nationwide uniform.

Social tariffs are implemented for electricity in ES, IT, FR and GR and for gas in IT, FR and PT. In IT and PT this is done with the involvement of the distribution company. Suppliers are responsible for implementation of social tariffs, with the exception of gas social tariffs in IT and PT. The mechanism in force in Italy can be considered as a mechanism to subsidise costs for specific (low-income) consumers.

Connection charges are defined "deep" when they are intended to cover both consumer specific costs and part of the cost of infrastructures shared among multiple network users. Deep connection charges are implemented in AT, HR, DE, LT, PT, SK, GR, SE and in gas by AT, DE, LT, PT, GB, PL, SE; FR, IR, LU, HU, MT, RO, FN for electricity and IR, LU for gas implement deep connection charges for large network users. All other Member States implement "shallow" connection charges, i.e. charges that cover only (and sometimes not entirely) the cost of infrastructures that are not shared among multiple network users.

Total distribution costs are split differently among types of consumers in different countries. In particular, the share of distribution cost paid by residential users ranges from 33% to 69% for electricity, while small gas consumers pay a share of distribution cost between 32% and 86%.

Generally distribution tariffs do not appear to be related to the consumer's (or consumer's type) withdrawal at times in which total load is highest[24][25].

[24] On the contrary it is common to charge consumers based on their "individual" maximum load, even if takes place at times in which the network is not highly utilized.

Rather than on sending short term signals, the weight placed in most countries on capacity-related charges is consistent with sending consumers long term price signals on the cost of developing the distribution system to serve additional demand. This logic is explicitly referred to by PT, for gas distribution tariffs. We notice however that geographical tariff averaging, implemented in some countries presumably according to a fairness criterion or income redistribution objectives, may distort the price signals delivered by distribution tariffs.

However, the quality of such long term price signals is unclear. In particular, as discussed in greater detail in section 0 distribution tariffs in most countries appear to rely on energy charges more than it would be consistent with the cost structure of DSOs: for household consumers, the weight of active energy charge is at least the 70% of the distribution electricity networks cost, being the Fixed and/or Capacity charges) around the 20-30% of the distribution network tariff charges. For large consumers the weight of energy component is lower than for household consumer, however such weight represents on average more than half of the distributions cost.

4.5. Network development

The following tables report, for each Member State, information on the main features of network development process for the electricity and gas sectors. In particular we consider:

- If a distribution network development plan is published and if it is subject to approval by the regulator or by the government
- If (and how) the distribution network development plan addresses:
    - Targets of embedded generation hosting capability
    - Quality of service targets
    - Issues related to system operations, at the distribution network level (demand response, storage systems, etc.).

[25] With the partial exception of IE, for gas distribution tariffs, and FR and GB for electricity tariff.

Table 17: Electricity Distribution network development

Country	Published distribution network development plan (DNDP)	Investments approved by regulator/ government	DNDP contains hosting capacity target	DNDP addresses quality of service issues	DNDP addresses "system operation" issues
AT	No Notified to NRA, not published	No	No	No	No
BE	n/a	n/a	n/a	n/a	n/a
BG	n/a	n/a	n/a	n/a	n/a
CY	No However, the DSO considers (in an informal planning process) the likely long-term developments in specific geographic areas (i.e. cities).	No	No	N.a.	No
CZ	No. Only TSO publishes development plans	No	No	No	No
DE	√ Only on HV level	√ Only for certain investment (Investment measures) and only formal check for eligibility	No	No	No
DK	No Not published	No	No	√ Quality of service targets are considered when general system layout is determined	No
EE	n/a	n/a	n/a	n/a	n/a
ES	No	√	No	√	No
FI	√ DSO develops plans every 2 years and notifies them to the NRA (but they are not published).	No	No	√	No
FR	No Not published	√ Only for smart metering programme	√ DSO has to publish the generation hosting capacity for each HV/MV substation	No	No
GR	No	√	No	No	No
HR	√ Approved by the	√ Investments plans are	No duty to connect all the	√ Analysis under	√ Analysis on RES

Country	Published distribution network development plan (DNDP)	Investments approved by regulator/ government	DNDP contains hosting capacity target	DNDP addresses quality of service issues	DNDP addresses "system operation" issues
	regulator and published every year	subjects to official approval	renewable capacity that applies	preparation	targets, and demand flexibility under preparation
HU	No Only a National Development Plan for transmission lines is submitted to the NRA	No	No	No	No
IE	No Notified to NRA, not published	No	No	√ DSO takes quality of service targets into account when developing DNDP	√ Integration of RES-E generation
IT	√ Prepared, updated and published annually	No	Yes	√	No
LT	No Only submitted to NRA	√ Only large investment	No	√	√ Assumptions on future demand flexibility
LU	No Only notified to NRA	√ Soft approval	No	No	No
LV	n/a	n/a	n/a	n/a	n/a
MT	No DSO notified to the regulator but not approved and not published	No	No	√ Limited	No
NL	√ Published every 2 years	No	No	√	No
PL	√ Published every 3 years, looking 5 years ahead	√	No	No	No
PT	√ Submitted every 2 years	√	No	√	No
RO	√ There are detailed investment plans that can be treated as development plan. They are approved by the regulator and not published.	√	No	√	No
SE	No	No	No	No	No
SI	√ Published for all voltage levels > 110kV	√	No	√ taken as an input	No

Country	Published distribution network development plan (DNDP)	Investments approved by regulator/ government	DNDP contains hosting capacity target	DNDP addresses quality of service issues	DNDP addresses “system operation” issues
SK	No	No Subject to RONI approval			
GB	√ 5-Year plan published annually with mid-year update	No	No	√	No

Table 18: Gas distribution network development

Country	Published distribution network development plan (DNDP)	Investments approved by regulator/government	DNDP contains coverage targets	DNDP addresses quality of service issues
AT	No	No		
BE	n/a	n/a	n/a	n/a
BG	n/a	n/a	n/a	n/a
CY	n/a	n/a	n/a	n/a
CZ	No. Only TSO publishes development plans	No	No	No
DE	No	√ Only for certain investment (Investment measures)		
DK	No Not regulated	No		No
EE	n/a	n/a	n/a	n/a
ES	√ (some Regions)	No	√	No
FI	No	No	No	No
FR	No Not published	√ Legally subject to economical study and must comply with Benefits/Investment ratio. The methodology is audited by the NRA		No
GR	√	No	No	No
HR	√	√	√	No Planned to be implemented starting from 2nd regulatory period
HU	No	√	No	No

Country	Published distribution network development plan (DNDP)	Investments approved by regulator/government	DNDP contains coverage targets	DNDP addresses quality of service issues
IE	No	√		No A Separate Performance Report is published that outlines service targets and performance
IT	No	√ Investments in network development are governed by the local authorities	n/a	n/a
LT	No Notified to the NRA	√ Soft approval	No	No
LU	No Notified to the NRA	√ Soft approval		No
LV	n/a	n/a	n/a	n/a
MT	n/a	n/a	n/a	n/a
NL	√ Published every 2 years	No	No	√
PL	√	No	√	√
PT	√	√	No	Not explicitly
RO	n/a	n/a	n/a	n/a
SE	No	n/a	n/a	n/a
SI	No	√		No
SK	√, publishes but not approved by the NRA	No	No	No
GB	√ 10-Year plan, prepared annually	No		√

The depth of ex-ante scrutiny of the distributors' investment is diverse among member States. For electricity, only HR, DE (for network assets at voltage greater than 110 kV), GB, IT, PL, NL, PT publish distribution network development plans. Only in six countries distribution network development plans are approved by regulators, while in three (FR, DE, LT) the regulator approve only selected investments. The same holds for gas distribution, with plans published only in HR, GB, GR, NL, PT, and approved only in few countries. A distinguishing feature of gas distribution in IT and ES is the involvement of the local government in network development planning.

With regard to the topics covered in the plans, in some cases quality of service issues are explicitly addressed in the plans, but hosting capacity targets for embedded generation (in electricity) are generally not indicated in the plans. The same holds for issues related to system operations, such as demand side flexibility, storage systems or control of embedded generators.

The distribution network development decision-making process, then, appears less structured and transparent than the transmission network development process in most member States. This is consistent with the traditional features of the gas and power distribution service:

- A focus on universal network coverage and continuity of service;
- Little generation capacity and dispatchable resources (such as controllable load or energy storage equipment) connected to the distribution network
- Unidirectional power flows, from transmission network interconnections to consumers.

4.6. Embedded generation

The following table reports, for each Member State, information on the activities of distributors as system operators for the electricity sector only. In particular we consider if distributors:

- Dispatch embedded generators
- Dispatch interruptible loads
- Deploy other flexibility mechanisms, such as storage systems.

Table 19: Distribution system operations

Country	Distributor can dispatch embedded generators	Distributor dispatches interruptible load	Distributor controls other sources of flexibility
AT	√ Only for security reasons	√	√ Demonstration projects
BE	n/a	n/a	n/a
BG	n/a	n/a	n/a
CY	No	No	No
CZ	√ Only asked by system operator	√	√ DSO can use a remote control system to switch on/off participating appliances
DE	√ Full dispatch authority on generators	√	√ Battery storage
DK	√ Only in case of planned work on the grid or breach of contract	No	No
EE	n/a	n/a	n/a
ES	No	No	√ Batteries and capacitors
FI	No	No	No
FR	√ Only in case the distribution system cannot host more injections	No	√ Smart grid pilot projects (battery packs, flexible loads); ripple control of electric water heaters
GR	No	No	No
HR	√ Only in case the distribution system cannot host more injections	√	No
HU	√ Only large embedded generators in case the distribution system cannot host their injections	No	No
IE	√ Only for security reasons	No	No
IT	No	No	√ Demonstration projects
LT	No	No	No
LU	√ Only in case the distribution system cannot host more injections	√	No

Country	Distributor can dispatch embedded generators	Distributor dispatches interruptible load	Distributor controls other sources of flexibility
LV	n/a	n/a	n/a
MT	√ Only large embedded generators are subject to dispatch by the DSO	No	N.A
NL	No	No	√ Demand response and flexibility provided by decentralised generation.
PL	√ DSOs are allowed to dispatch any generation units connected to the distribution network except for generation units with an installed capacity of 50MW or more	√ DSOs may curtail flexible loads if the safe operation of the grid is in danger.	No, unless a bilateral agreement is developed between the DSO and the flexibility provider
PT	No In case of security reasons, the DSO may be forced to require generators to disconnect.	No	√ capacitor banks and transformer taps for voltage control
RO	√ However third level of dispatching rights under the National Dispatch Center	√ Only for safety reasons in emergency cases	N.A
SE	√ Can dispatch RES generation plant connected to their networks	√	No
SI	No	No	√ Capacitators in primary substations
SK	√ Only large embedded generators	n/a	n/a
GB	√	√ DNOs can enter into bilateral agreements	√ Demonstration projects

In ten countries distributors don't have control on embedded generators. In ES renewable generators' are dispatched centrally by the system operator, even if these generators are connected to distribution networks. In CZ and RO, distributors act as agents of the system operator in issuing dispatch orders to renewable generators.

In about half of the European countries, distributors control interruptible loads. In AT, FR, DE, SI, ES, NL, PT distributors control further sources of flexibility or are engaged in pilot projects involving deployment of storage capacity and smart grid technologies.

The role of electricity distribution companies appears to be changing, mainly as a consequence of the expanding share of generation capacity hosted by the distribution network.

From the traditional role of managers of a basically passive infrastructure, distributors are starting to evolve into system operators, with (some) control on generation capacity, flexible load and other sources of flexibility, like storage capacity.

Such trend is at a very early stage and it appears that a set of organizational arrangements explicitly codifying the new role of distributors has yet been developed in any member States.

4.7. Metering

The following tables report, for each Member State, information on the involvement of distributors in meter-related activities for the electricity and gas sectors. In particular we investigated:

- The role of distributors in metering,
- If distributors enjoy a monopoly in metering activities
- Deployment targets of smart metering systems.

Table 20: Electricity Metering

Country	Distributor performs metering /own meters	Distributor enjoys monopoly on meter-related activities	Smart-metering deployment calendar
			Current/Expected level of penetration
AT	√	√ De facto	2015_10%/ 2017_70%/ 2019_95%
BE	n/a	n/a	n/a
BG	n/a	n/a	n/a
CY	√ DSO is responsible for metering; the meters are owned by the network owner	√	0% current/ no formal plans for roll out
CZ	√	√	Do not have plans for a large-scale rollout of smart meters.
DE	√	No	2014_1%/at the end of the mandatory roll-out_30%-50%
DK	√	√	2014_57%/2020_100%
EE	n/a	n/a	n/a
ES	√	√	2014_35%/ 2016_70%/ 2020_100%

Country	Distributor performs metering /own meters	Distributor enjoys monopoly on meter-related activities	Smart-metering deployment calendar
			Current/Expected level of penetration
FI	√ Performs metering and owns most meters (some meters are leased)	√	2013: 93% of all customers have a smart meter; Overall aim (without deadline) for 100% roll out
FR	√	√	2014_0.5%/effective roll out 2015-2021
GR	√	√	2016: 0.5% 2017: 2.2%
HR	√	√	N/A
HU	√	√	Final implementation of Smart meter is still in progress. There is no final decision on deployment of Smart metering system.
IE	√	√	Mass roll-out in 2018
IT	√	Monopoly on consumer-side metering; no monopoly on generation-side metering	Full deployment at all voltage levels
LT	√	√	2014_1% (commercial)/ +3000 pilot project for residential in 2015
LU	√	√	2014_0%/2018_95%
LV	n/a	n/a	n/a
MT	√	√	Smart meters installed and billed remotely by the end of 2013 by customer category: Residential: 73.257; Domestic: 32.310; Non-Residential: 11.816. Note: The number of smart meters does not correspond exactly to the number of consumers with smart meters because consumers with an RES generator are normally provided with two smart meters : A PV meter and import /export meter
NL	√	√ Monopoly on metering services for small customers only	2020: 100% smart meter rollout to customers
PL	Performs metering. DSOs own the householders and small businesses meters. Other customers generally	√	No formal plans for roll out

Country	Distributor performs metering /own meters	Distributor enjoys monopoly on meter-related activities	Smart-metering deployment calendar
			Current/Expected level of penetration
	own their meters		
PT	√	√	Continue with the deployment of large-scale smart metering pilot projects.
RO	√	√ However DSOs may externalize the activity	The deployment of smart meters is in the stage of approval of the pilot-projects, there are 120 000 clients included in this stage.
SE	Performs metering and responsible for all data management tasks, but they cannot own the meters	√	In 2013 all customers in Sweden already have a smart meter installed
SI	√	√	2014_31%
SK	√	√	Currently test operations on selected consumer groups are being conducted.
GB	√ DSOs are only obliged to maintain meters installed pre March 2007	No Market is liberalised	2015:12% / 2016: 17% / 2017: 29% / 2018: 47% / 2019: 67% / 2020: 100%

Table 21: Gas metering

Country	Distributor performs metering /own meters	Distributor enjoys monopoly on meter-related activities	Smart-metering deployment calendar
			Current/Expected level of penetration
AT	√	√ De facto	59% gas volumes are metered daily (or hourly)/No plans to deploy SMs to small consumers
BE	n/a	n/a	n/a
BG	n/a	n/a	n/a
CY	n/a	n/a	n/a
CZ	√	√	There is negative CBA in the Czech Republic so there is smart meters just in pilot projects

Country	Distributor performs metering /own meters	Distributor enjoys monopoly on meter-related activities	Smart-metering deployment calendar
			Current/Expected level of penetration
DE	√	√ De facto	n/a
DK	√	√	n/a
EE	n/a	n/a	n/a
ES	√ (large consumers own their meters)	√	Only large consumers (70% of gas volumes) are daily metered/no plans to deploy SM to small consumers
FI	√	√	1.3% of gas customers have a smart meter. There are no explicit plans for further future roll outs
FR	√	√	2014_1% daily metered/ 2016_ pilot project of 150, 000 meters for retail market and small companies/roll out 2017-2022/aim : 95%
GR	√	√	No smart meter roll out in 2013; no plans for future roll outs
HR	√	√ De facto, but customers can choose another provider of the meters	2013_11.6% daily metered / 2014_ pilot projects planned for the deployment of smart meters
HU	√	√	There are several ongoing pilot projects.
IE	√	√	2014_24% daily metered/NRA conducting stakeholder engagement and consultation to inform the optimal smart metering solution
IT	√	√	Around 0.5% of gas customers had a smart meter installed in 2012. Future roll out plan: G40 unit customers: 100% by 31 Dec. 2014; G16 and G25 unit class customers: 60% by 31 Dec. 2014; 100% by 31 Dec. 2015; G10 unit class customers: 15% by 31 Dec. 2014; 30% by 31 Dec. 2015 Small customers (G6 units or lower): for distributors with more than 200,000 delivery points (as at 31 Dec. 2013):

Country	Distributor performs metering /own meters	Distributor enjoys monopoly on meter-related activities	Smart-metering deployment calendar
			Current/Expected level of penetration
LT	√	√	3% by 31 Dec. 2014;; 60% by 31 Dec. 2018 2014_850 remote reading meter/ Ministry of Energy is now preparing smart meters full roll out schedule which will start with a pilot project
LU	√	√	2014_0/2020_95%
LV	n/a	n/a	n/a
MT	n/a	n/a	n/a
NL	√	√ Monopoly on metering services for small customers only	In 2013, 8% of customers had a smart meter installed. 2020: 100% smart meter rollout to customers
PL	√	√	Information on this is not available
PT	√	√	Portugal concluded CBA with negative results and decided not to proceed with large-scale roll-out of smart metering systems. No smart meters installed so far.
RO	n/a	n/a	n/a
SE	√ Performs metering and is responsible for data management, but cannot own the meters	√	In 2012, 3.4% of customers had a smart meter installed. No explicit information available on future deployment of smart meters
SI	√/No Metering device may be owned by the gas DSO or the customer	√	2014_0.5%/deployment of smarts meters is foreseen for customers with high consumption and with less predictable demand profile
SK	√	√	Smart meters are currently standard placed in the off-take category above 60 000 m3/year. Currently ca. 4 800 smart meters are placed.
GB	√ DSOs are only required to provide metering services when requested to do so by a gas supplier	No, the metering market is liberalised	Future roll out (all customers): 2014 – 1.5%; 2015 – 15%; 2016 – 26%; 2017 – 44%; 2018 – 65%; 2019 – 85%; 2020 – 100%

In all Member States but the GB, gas and electricity distributors are responsible for metering, under a formal or *de facto* monopoly regime. Distributors typically own meters, even though in some countries large consumers own their meters.

Meter data management activities are separated from meter ownership in GB, where data management is carried out by an independent company, and in SE, where data management is a distributors' responsibility, but distributors do not own meters.

Roll out of electricity smart meters is progressing at different pace in different member States:

- IT, FI, SE, have already 100% or nearly 100% coverage,
- Most countries will reach in 2014 coverage below 10%; these are: AT, FR, IE, LT, CY, GR, LU, CZ, HU, PT, PL, RO, DE, RO, SK; in some of these countries pilot projects are being carried out,
- Most countries have plans to reach full or almost full coverage by 2020, with the exception of DE, CZ, HU, PT, RO, SK.

Mass roll-out plans of gas smart meters have been approved only in FR, GB, IT, NL, LU; they are expected to deliver full or almost full coverage by 2020. Currently in most countries smart gas meters are deployed only for large consumers.

5. Task 4 - Identification of best practices to calculate and design distribution tariffs

5.1. Introduction

We organize the analysis around the following topics, each one investigated in a section of the chapter:

- Industry structure (section 5.2)
- Revenue setting mechanism (section 5.3)
- Tariff setting mechanism (section 5.4)
- Network development (section 5.5)
- Flexibility measures (section 5.6)
- Metering (section 5.7)

5.2. Industry structure

The distribution activity in the EU Member States has developed under different governance models. Generally, it fell under the responsibility of municipalities or of relatively small district authorities (e.g. Germany, Austria, Netherlands, and Belgium). This holds in particularly for gas distribution, which could be substituted by other fuels and was normally not subject to a universal service obligation. Therefore, its availability was often a choice left to local powers.

At the opposite extreme, in several countries a unitary organisation of the service at national level, with a view to providing a basic service at uniform conditions to the whole country has been selected: this has been the case mostly for electricity (e.g. the Great Britain, France, Italy, Slovenia,…) but in some countries also for gas (the Great Britain, Spain, most of France).

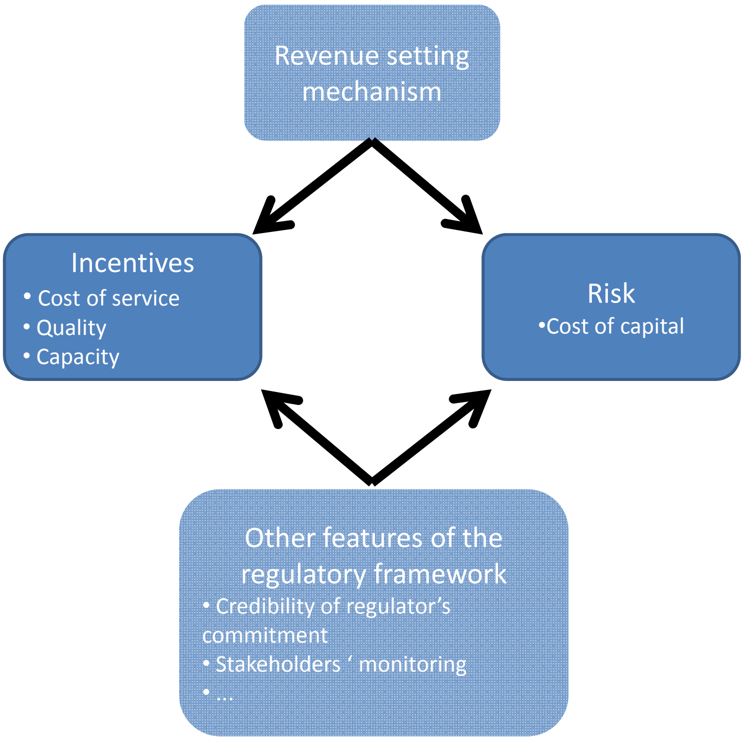
Between these extremes, several countries have followed intermediate models, with distribution in the hand of provinces or larger districts. Examples are found in the Czech Republic and Portugal. The liberalisation process has triggered remarkable changes in the structure of distributors, notably at country level. For example, Great Britain split its single gas distributor, setting up four smaller ones, sold to different companies. On the other hand, the Netherlands have promoted concentration of distributors, which have been reduced by an order of magnitude.

Data collected by the study may be the basis for further studies on the relative merits of alternative industry structures, possibly providing guidance to Member States that could be interested in promoting further restructuring.

5.3. Revenue setting mechanism

Providing incentives to firms enjoying an information advantage over the regulator generally requires that some risks be placed on the firms and higher expected rate of returns have to be granted in order to compensate investors for that risks. In this section, we compare alternative revenue setting mechanisms in terms of:

- Incentives provided to distributors to make efficient long-term decisions and to carry out their operations at minimum cost;
- Risks placed on distributors and expected rate of returns necessary to attract capital in the industry.



Other features of the institutional framework governing the distributors' activity may have a strong impact on the incentives-risk trade-off. These include for example the credibility of the regulator's commitments, the involvement of the stakeholders in monitoring the distributor's performance and the industry structure. However, we will focus here on tariff-related issues.

The position of a country's regulatory system on the incentive-risk trade-off results from the interplay of all its features. Alternative frameworks may achieve similar balance between risks and incentives despite using different constraints. Similar formal structures of the regulatory framework may result in materially different outcomes depending on the interaction between regulator and regulated firm when the system's parameters are set. Finally, exogenous conditions may impact on the effectiveness of certain regulatory mechanisms.

For these reasons it is impossible to identify a "best" set of regulatory mechanisms and the discussion on best practices needs to be cast in terms of general features of the regulatory framework, which can be achieved by alternative mechanisms. In the remaining of this section we characterize desirable features of regulatory system for electricity and gas distribution, and relate them to the mechanisms implemented in Europe.

❖ ***Risk allocation between consumers and regulated firms***

Other things equal, higher expected rate of returns have to be granted in order to compensate investors for risk; therefore a desirable feature of regulatory mechanisms is that they do not exposure distributors to risks caused by factors that are not under their control.

As discussed in section 0 the revenue setting mechanisms implemented in most Member States limit exposure of distributors to risks that are not under their control. First, distributors are typically shielded from volume risks. This is consistent with the modest price elasticity of demand such that distributors have limited, if any, control on the demand for their services. The approach used in the Czech Republic seems to be fairly representative of the typical, and generally-optimal, risk allocation approach used in Member States. That country´s regulatory system does not place volume risk on the DSO; rather, an allowed revenue target is set for specific years, and if a DSO doesn´t receive, or exceed, the revenue target due to lower-than-anticipated demand, revenues are corrected in the following year´s tariffs.[26]

Second, generally European distributors bear little investment risk related to:

- Investment selection, and
- Investment implementation.

We refer as risk related to investment *selection* to the risk that some assets turn out to be not useful, for example because expectations of demand growth or generation connections do not materialize.

Our survey of the European countries shows that such risk is normally not placed on distributors[27]. An alternative approach would focus on incentivising distributors to take efficient investment decisions by:

- Granting distributors full autonomy in investment selection and;
- Placing on distributors the cost of any stranded assets.

We discuss further in the section on optimal investment decisions the relative merits of alternative regulatory schemes in terms of incentives to select the optimal investment path. Here we limit ourselves to noticing that the distribution industry appears to be going through an investment cycle for the deployment of smart technologies and the implementation of capacity upgrades necessary to increase the distribution networks' capacity to host embedded (renewable) generators and more flexible demand. Since incentive based mechanisms place risk on the regulated firms, during periods in which attracting capital in the industry is the main concern the cost of providing incentives is higher than in static situations. This, other things equal, moves the optimal point in the trade-off between incentives and risks, towards schemes that leave less risk on the regulated firms and are therefore able to attract capital at lower cost, as opposed to mechanisms delivering high-powered incentives. This holds all the more if, as it appears

[26] This, and other, risk mitigation measure(s) used in the Czech Republic´s distribution regulatory framework are discussed in Section 2.2 of the Czech Republic electricity report (page 189 of this report),

[27] However, in some countries ex-post assessments of the investment's opportunity is possible,

to be the case, new technologies are being implemented, with uncertain cost and performance.

However, as discussed in section 5.5, if consumers are to bear most or the entire investment risk thorough ex-ante scrutiny of the distributor's investment decisions by regulators is necessary. In Great Britain the regulator undertakes extensive ex-ante assessments of DSOs´ business plans (i.e. their investment plans for the following 8-year regulatory period). Specifically, the regulator analyses each DSO´s plan in terms of efficiency, costs, proposed means of dealing with risks and uncertainties and ability to deliver required outputs.[28]

We refer as risk related to investment implementation to the risk that the cost of new network assets turn out to be greater that the corresponding revenue allowance granted to the distributor. This risk is a feature of schemes that incentivize distributors to minimise the cost of deploying assets agreed with the regulators – whose value will therefore be included in the regulatory asset base. In such model, the regulator and the distributor agree, at the beginning of the regulatory period, to a certain investment pattern and to the corresponding allowed revenues. If the distributor implements the investment at a cost lower (larger) than the pre-determined level, the distributor retains part of the savings (bears part of the extra-cost).

The power of such schemes depends on conditions that can only be assessed empirically. In particular, an information asymmetry between the regulator and the firm on the investment's cost is necessary to justify implementing incentive-based schemes to reduce investment costs. However, if such asymmetry is very large the distributor might end-up with large rents. In that situation, then, a mechanism allowing recovery of actually incurred costs might serve the consumers' interests better than an incentive scheme, as higher investment costs due to lack of incentives might be more than offset by lower information rent. Second, incentives to minimize investment cost may come from other sources. For example, the obligation to procure large network components via tenders relieves the regulator from implementing an incentive-based mechanism to minimise the corresponding costs.

❖ ***<u>Benchmarking and standard costing</u>***

Benchmarking and standard costing can and are used across Europe in two ways:

- As an element of the regulator's toolbox;
- As a core element of the revenue setting scheme.

As items in the regulator's toolbox, benchmarking and standard costing provide information on efficient distribution costs. By reducing the information asymmetry between regulator and regulated firm, benchmarking allows the regulator to set up more powerful (or less expensive, in terms of rents left with the distributors) incentive-schemes.

In particular, cost benchmarking or standard costing may provide valuable information on the cost of new or replacement infrastructures, especially if such infrastructures are based on consolidated technologies. Availability of robust information about the cost of new assets allows mitigating the firm's information advantage and to support the introduction of

[28] This is discussed in section 4.4.2 of the Great Britain country report (electricity).

incentive schemes inducing distributors to minimize the cost of network upgrades, like those discussed in the previous section.

In Denmark for example, DSOs are benchmarked against each other on OPEX; however, if a DSO incurs extraordinary costs due to an unexpected extraordinary event, it can receive an exemption of those costs from the benchmarking process.

As a core element of the revenue setting scheme, benchmarking and standard costing are used directly to determine the distributors' allowed revenues. In case of benchmarking, for example, allowed unit revenue for all distributors could be set equal to average unit cost across all other distributors in the previous year. In case of standard costs, the distributors' allowed revenues would instead be set equal to standard costs.

With benchmarking and standard costing each distributor's allowed revenues are to a large extent independent from the distributor's cost. That provides the incentive to minimize costs.

Benchmarking and standard costing may be implemented on operating costs only or on total costs. The latter scheme is commonly referred to as Totex regulation.

Provided the conditions discussed below are met, Totex regulation may address multiple regulatory objectives, including incentivising the distributor to:

- Carry out the optimal network development strategy;
- Select the optimal mix of operating and capital costs
- Eliminating inefficiencies.

Both Germany and Austria undertake benchmarking on Totex for the determination of their X factors to be used in their price controls. In the case of Germany, the information deficit issue for Capex costs of DSOs proposed investments is assumed to be addressed, because cost efficiency is promoted via Totex benchmarking.[29]

A crucial necessary condition for benchmarking based revenue setting mechanism to be effective is that the (efficient) cost be the same for all distributors. If that is not the case revenue setting mechanisms based on benchmarking may result in:

- Unjustified rents for firms operating in low cost areas;
- Economic sustainability problems for firms operating in high cost areas.

Further, implementation of an effective revenue setting mechanism based on benchmarking may present challenges in the following areas. First, it might be difficult to characterize a significant empirical relation between distribution costs and distribution outputs, such as number of connections, energy delivered, maximum system power, hosting capacity of embedded generation, quality of service. The same difficulties may arise in assessing the impact on costs of exogenous factors, such as population density, climatic conditions.

Second, if the technological environment is dynamic and uncertain, cost benchmarking may provide little information on future costs. Further, cost benchmarking and uncertainty about the performance of alternative technologies may induce risk adverse distributors to adopt the same technology rather than to experiment with potentially more efficient alternatives, as the mechanism is such that costs borne by all firms are passed on to consumers.

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[29] This application is described further in section 2.2 of both Austria and Germany´s country analyses, discussed on page 155 and page 200 of this report, respectively.

Finally, under (Totex) benchmarking regulation distributor-specific stranded investment would not pass on to consumers. For example, if all benchmarked distributors had carried out the same investments, under the same expectation of demand growth, and demand turns out to be lower than expected only in some distribution areas, tariffs based on benchmarking would not allow distributors operating in those areas to recover total costs. This feature might increase materially distributors' risk and cost of capital and, ultimately, distribution tariffs.

Additional provisions can be introduced to mitigate the impact of those issues, at the price of further distortions, for example:

- If a standard cost function - linking costs and outputs - turns out to be difficult to estimate, it might be easier to characterize a relation between distribution costs and some inputs, such as indicators of the network's dimension (kilometers of lines, number of substations …). However, the input selection is to some extent under the firm's control. Therefore, reference to inputs, instead of outputs, in order to assess allowed revenues may distort the regulated firm's incentives to cost minimization
- If location-specific cost determinants are impossible to reflect in a robustly estimated cost function, distributors might be granted the option to apply for an individual cost assessment whose outcome would be used to set allowed revenues. However, this option can be expected to attract distributors located in high-cost areas, while low-cost outliers would select the benchmarking mechanism.

Whether the conditions for successful implementation of benchmarking regulation, and in particular homogeneity of cost conditions, are met is a matter for empirical assessment in each country. We note, however, that setting allowed revenues based on cost benchmarking or standard cost might be the only option if the industry structure is highly fragmented, so that analysing cost information provided by (hundreds of) distributors would entail unreasonable administrative costs.

❖ ***<u>Optimal investment decisions and trade-off between operating cost and capital cost</u>***

Regulatory systems that make total allowed revenues independent of the firm's behaviour provide incentives to total cost minimisation and therefore induce distributors to select the optimal investment path and ratio between operating and capital expenses.

As discussed in the previous section, benchmarking is a way to make allowed revenues consistently independent of each firm's cost. Therefore, provided the prerequisites for its successful implementation hold, benchmarking provides incentives to distributors to make optimal investment decision and select the efficient opex/capex ratio.

With the alternative "building block" approach, implemented in most European countries, allowed revenues are set for a multi-year regulatory period, at the start of period. Incentives to cost minimisation result from the independence of allowed revenues from the firm's actual cost during the regulatory period.

Some features of this model, however, may reduce its incentive power. First, predetermination of allowed revenues is typically based on the distributor's proposed investment plan, which the regulator implicitly ratifies at the beginning of the regulatory period by allowing recovery of its expected cost during the regulatory period. In other terms allowed revenues are not independent of the investment decision, and there regulator is more or less explicitly involved in such decision.

During the regulatory period the distributor could and would have the incentive to depart from the original investment strategy – including the capex/opex ratio – in favour of a lower cost alternative, if one existed. This is the case since the lower cost strategy would allow the distributor to take advantage of the predetermined allowed revenues that were computed based on the more costly strategy, until the next price review. However, in the context of repeated interactions with the regulator, we would expect that this is unlikely to happen, as it might be interpreted, for example as evidence that:

- The firm concealed the more efficient investment option at the revenue setting stage, or
- The firm is delaying necessary investment to obtain profits in the short term, while consequences of such delay on, say, quality of service, will materialize in the future.

This holds to the point that claw back of tariff revenues is implemented in some countries in case the distributor does not realize planned investment. In addition, as discussed in section 0 (task 3) several measures are commonly put in place in order to limit the risk that invested capital turn out to be under-remunerated. These features may reduce, in practice, the ability of the revenue setting mechanisms to drive the firm's investment decisions, and therefore the capex/opex ratio selection. [30]

Second, the ability of the revenue setting mechanisms to induce efficient investment decisions is likely to be reduced by the limited duration of the regulatory period. For illustrative purposes, consider a system based on pre-determined total revenue cap, possibly dependent on some output variables. Under this scheme, during the regulatory period revenues are independent from total actual cost. The distributor has to deliver the outputs agreed with the regulator and bear the corresponding cost, in exchange for the pre-determined revenues. As a consequence the distributor's profit maximising strategy consists in minimising total cost. However, in order to provide correct investment incentives, the regulatory period has to be at least as long as the time-horizon relevant for the distributor's investment assessment. If, for example, the benefit of an investment in terms of lower operating costs is expected to materialise in 15 years, total revenues must be fixed for at least 15 years for the distributor to receive the correct incentives to invest. If, on the contrary, a tariff review is expected to transfer the benefit of the investment to the consumers in the form of lower tariffs after only 5 years, the incentive for the firm to substitute capital for operating cost would be curbed[31].

Keeping allowed revenues fixed over the very long period necessary to provide optimal investment incentives would make departure of actual costs from allowed revenues likely; consumers would then have to pay a high risk premium to attract capital in such a risky enterprise.

We recall incidentally that experience in the transmission sector confirms that financial incentives aimed at inducing system operators to make optimal network development decisions are very hard to design and implement. There are no indications that regulators that have implemented such mechanisms regard them as a substitute for

[30] This holds to the point that claw back of tariff revenues could take place if the distributor does not realize planned investment.

[31] Notice that the argument holds even if the distributor is allowed to recover the entire invetsment cost. What distrots the distributor incentive is the limited duration of the period in which it can appropriate the variable cost saving.

careful monitoring of the system operator's plans. We will further address distribution network development issues in section 4.5.

❖ ***<u>Incentive-based mechanisms on operating costs, quality of service and on other distributor's targets</u>***

In most countries incentive based mechanisms are implemented to induce distributors to reduce operating costs. These mechanisms are based on:

- (Various implementations of) standard costing, mainly based on the comparison of the costs of distributors operating in different areas and;
- Predetermination of allowed revenues for a certain number of years, irrespective of actual operating cost.

Incentive-based mechanisms have proved very effective in inducing operating cost reductions in several countries, including for example in Great Britain and Italy. In Italy for instance, OPEX are subject to a price cap and at the beginning of each new regulatory period the new cap price is set so that 50% of the efficiency gains achieved (that is, the difference between actual and allowed costs) by the DSO in the previous period are not transferred to the customers through reduced tariffs.[32] Instead, the savings are kept by the DSO, therefore providing a strong incentive to DSOs to reduce their OPEX.[33]

Financial incentives targeting quality of the distribution service in the form of penalties or premiums for quality levels respectively below or above pre-determined targets are part of the standard regulatory toolbox for distribution in Europe and have proven to be effective.

Incentive mechanisms targeting individual performances (or outputs) of the distributor's activity may be effective, provided:

- The performance level can unambiguously be measured;
- The value for the consumers of achieving the target can be assessed; this might be difficult if the performances that are incentivised have an indirect impact on the consumer's welfare[34];
- The regulator has enough information to develop an autonomous view on the cost for the distributor to achieve the target; otherwise consumers might end up paying high cost to induce the distributors to deliver the target performance.

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[32] This measure is considered in Section 2.2. of the Italian electricity country analysis, on page 379 of this report.
[33] This measure is considered in Section 2.2. of the Italian electricity country analysis, on page 379 of this report.
[34] An example, from transmission, is incentive systems on the TSOs to forecast accurately intermittent renewable production. The ability to forecast renewable production has an indirect impact on consumers, via lower system operation costs and/or greater security of supply. However, the relationship between the incentivised performance and the consumer's pay-off is complex and difficult to quantify.

5.4. Tariffs

Tariff setting responsibilities are split differently between regulators and distributors (and the Government, in Spain) in different Member States. In this respect, no clearly superior model has emerged from our analysis, provided the methodology and assumptions which tariffs result from are transparent and verifiable, at least by the regulator.

In all member States total distribution costs are allocated to different categories of consumers based on some notion of cost-reflectiveness. We find that greater transparency would be beneficial on:

i) The methodology to split total distribution costs among the different categories of consumers, typically consumers connected at different voltage or pressure level and

ii) The drivers for cost allocation to capacity and energy charges.

Traditionally, energy demand by small consumers has been price inelastic in the short term. In that context alternative methodologies to split costs among consumers would differ mainly in terms of wealth (re-)distribution, and fairness would be the relevant metric to assess them.

However, measures that are being introduced to exploit the flexibility potential of small consumer's electricity demand, and more generally policies focusing on efficiency in the electricity industry, would lead to emphasizing efficiency considerations in distribution tariff design.

We have not encountered tariff schemes providing short term price signals of distribution capacity availability on a continuous basis. We find this approach sound, as short term price signals of the scarcity of transportation capacity are efficiently conveyed via locational differentiation of the electricity prices.

Summer/winter or day/night distribution tariffs are implemented in a limited number of countries. When assessing these arrangements the following elements should be kept in account. First, in order for such tariff systems to convey correct price signals, distribution scarcity conditions must be accurately predictable far in advance of real time, which is rarely the case.

Second, given the typical structure of distribution networks[35], persistent distribution scarcity conditions are likely to place continuity of service at risk and therefore are unlikely to be a feature of an optimally dimensioned network[36]. In addition, addressing a structural shortage of distribution capacity by systematically curtailing embedded renewable generation (even though through price signals) would run against the very purpose of renewable generation support, which is maximising renewable production. For these reasons we would expect that

[35] Less meshed than transmission networks.

[36] Notice incidentally that, in this respect, distribution and transmission differ. In particular, insufficient transmission capacity typically results (only) in higher generation cost and therefore optimally dimensioned transmission system may feature some scarcity situations. This happens because transmission networks are typically highly meshed. On the contrary, distribution networks traditionally feature a more tree-like topology, consistent with their function of transferring a unidirectional power flow from transmission to the consumers' premises. With such a topology, lack of distribution capacity is likely to result in frequent service disruptions; these are very costly because of the high cost of unserved load. For that reason it is unlikely that an optimally dimensioned distribution system feature recurring scarcity situations.

sending short term scarcity signals to ration the use of distribution network should be normally unnecessary.

Third, in case scarcity conditions happen to be a structural feature of a distribution system, charging structures fixed well in advance of real time are highly imperfect substitutes for dynamic pricing schemes. In particular, the distinguishing feature of such schemes is that either distribution charges or energy prices vary on a continuous basis and by location in order to balance supply and demand of (distribution) transportation services. The merits of alternative forms of dynamic pricing have been extensively discussed in the context of electricity transmission. Reviewing that discussion is beyond the purpose of this report[37]. It suffices to recall that, in all practical applications locational energy price differentiation has been favoured over dynamic charging of network services. However, we are not aware of any application of either locational energy prices or dynamic network charging to distribution.

Finally, for the sake of completeness we recall a pricing scheme often referred to in the discussion on optimal distribution tariffs: "critical load" pricing. The distinguishing feature of critical load pricing is that high distribution charges apply when the distribution system's load peaks. Two possible implementations of such scheme can be conceived. First, a critical load charging structure set ex-ante, based on forecasts of the hours in which distribution peak-load will occur. This approach suffers the limitations of all schemes based on pre-determined tariff structure, discussed above. In particular, charges fixed ex-ante provide strong signals to network users as to when they should reduce network use but do not guarantee that this happens when capacity is really scarce[38].

Alternatively, critical pricing can be implemented ex-post. In this version, the hours in which system peak was reached are identified after-the-fact and injections and withdrawals that took place at those times are subject to higher distribution charges. This version of critical load pricing mechanism can be regarded as a simplified form of dynamic network charging. In particular, with this form of ex-post critical load pricing:

- Scarcity hours are correctly identified, like in an ideal dynamic network charging system;
- The level of the charges applied in those hours is pre-determined, while in an efficient dynamic pricing system such charges would take, at each time, the value that balances supply and demand of transportation capacity.

When sending short term scarcity signals is unnecessary or impossible, distribution tariff structures based on long term cost causation criteria, as those currently implemented in most Member States might be appropriate, if anything on fairness grounds.

Based on economic theory, as reflected in the cost allocation methodologies used in several countries, appropriate cost drivers for such tariff schemes appear to be:

- The consumer's withdrawal at the distribution system's peak, as an indicator of the consumer's responsibility in causing the cost of shared distribution assets. Proxies for this cost driver are commonly used. In France, for example the load factor of contracted connection capacity – i.e. the ratio between consumption and contracted

[37] Interested readers are referred to, for example, Dmitri Perekhodtsev and Guido Cervigni, Chapter 4, Congestion management and transmission rights, in *The Economics of energy markets*. *Theory and policy*. Pippo Ranci and Guido Cervigni editors, Edward Elgar Publisher, 2013.

[38] A variation of this argument is known as "shifting peak". This occurs in case most network users move away from high-priced hours and cause peak-load to move to low-priced hours,

connection capacity – is used as a proxy of the consumer's responsibility in causing distribution costs. We expect that once smart meters are deployed, charging consumers directly based on such cost driver will be possible.

- The consumer's maximum withdrawal, as an indicator of the consumer's responsibility in causing the cost of consumer-specific assets.

We conjecture, that increasing consistency between the structure of distribution tariffs and the structure of distribution incremental costs would result, in most countries, in greater reliance on capacity related charges over energy related charges, compared to the current situation and, in some countries, to greater geographical differentiation.

Both shallow and deep connection charges are used in Europe and we find no compelling reason to favour one approach over the other. Deep connection charges are (more) consistent with a logic of network expansion driven by the connection requests. On the contrary, shallow connection charges are (more) consistent with an approach in which generation hosting capacity is developed in anticipation of connection requests. We were not able to characterize the policies of the Member States in this area and a discussion of the relative merits of the two approaches to network development is beyond the scope of this project[39].

However, we find that as the share of embedded generation increases:

- Rights and obligations for connected generators should be clearly established and consistently enforced; in a context of very high penetration of renewable embedded generation such obligations could include, for example, a duty to participate in the markets for ancillary services, or limitations to their right to inject power in the system in case such injection caused unreasonable re-dispatch cost.[40] In France for example the DSO can require embedded generators to disconnect in the event that the distribution system cannot handle their power injections. Similarly, in Luxembourg, DSOs can require embedded generators to disconnect if network conditions require it, and DSOs can also directly control flexible loads.[41]

- The (expected) cost for the system to enforce the rights granted to embedded generators, for example re-dispatch or network upgrade costs, should be reflected in connection charges in order to coordinate generation and distribution investment decisions.

In the electricity distribution sector in Germany for example, the connection charge is meant to cover the cost of the facilities that are specifically set up to serve the customer and the connection to his housing. In addition, the consumer is obliged to pay a contribution towards the cost of the reinforcement of networks and shared resources.[42]

Consumers in Germany are obliged to pay the connection costs and a contribution towards the network costs. The DSO prepares an estimate based on its cost but the customer is free to procure the necessary works from a different provider. For consumers and generators alike, the DSO may refuse connection only if it is impossible or if it would entail an

[39] The former approach has the advantage of reducing the risk of stranded investment. However, implementation of network upgrades after the user's commitment may delay connections.

[40] Another approach to incentivise generators to limit their injections is to apply a charge to them, which is geographically- and/or timely-differentiated to match incentive and network needs.

[41] As discussed in Sections 4.2 of the France and Luxembourg country analyses, on page 284 (France analysis) and page 417 (Luxembourg analysis) of this report.

[42] As discussed in section 3.2 of the German electricity distribution analysis, on page 405 of this report

unreasonable cost. Upon request of the requesting party, in the case of lack of hosting capacity the reasons must also contain meaningful information regarding the concrete measures and the costs associated therewith would be individually necessary for development of the system to achieve connection to the system.

5.5. Network development

Our analysis in section 0 (task 3) suggests that electricity and gas distributors in Europe enjoy greater autonomy than transmission system operators in taking network development decisions, since network development plans are generally not published and subject to public consultation; furthermore, in most countries distributors are not subject to the regulator's approval. We notice incidentally that in no country electricity distribution network development plans appear to indicate targets on generation hosting capacity.

In some respects such governance model of network development is consistent with the traditional features of the distribution business. In particular:

- The outputs of distribution were easy to characterize and verify. Broadly these output can be characterized as: making the electricity service universally available, reaching a reasonable coverage of the population with gas networks and fulfilling certain quality levels, mainly in terms of service continuity;
- Technologies to realize and manage traditional passive distribution networks were consolidated and the main development decisions concerned network topology and asset sizing.

The content of the distribution service, in particular for electricity, can be expected to change in the future if the current policy and technological trends persist.

- First, multiple resources connected to distribution networks will be dispatchable[43] including embedded generators, flexible loads, storage systems and other active network equipment. Further, smart-grid technologies will make the network topology more dynamic than in the past.

  This evolution will present distribution system operators and regulators with new trade-offs both in day-by-day operations and in network development. For example developing demand side flexibility might be an alternative to network upgrades; deploying network intelligence, an alternative to building new lines and transformers.

- **Second, interaction between development decisions at the transmission level and at the distribution levels might become more complex,** as the two become in some respects more similar.
- **Third, network development decisions will have to be coordinated with the outcomes of other policy streams.** For example, as the share of embedded generation grows, network development plans and renewable generation targets need to be coordinated, to prevent that in some areas network upgrades turn out to be useless – because no generation connection is requested – while in other areas

[43] By dispatchable we mean that injections and withdrawals by those resources will be controllable. The regulatory and trading arrangements governing dispatch of embedded generators and flexible loads are still being developed, including the form of the distributors' involvement.

network development fails to keep up with connection requests by generators.[44] Some countries currently have more clearly-defined approaches to coordinating and integrating (network development, RES integration and hosting capacity) targets compared to other countries. For instance, in Slovenia, RES targets are explicitly taken into consideration within the network development plan to forecast hosting capacity requirements;[45] in Lithuania, Government-set RES targets are explicitly used as an input in the distribution development plan, which must make provisions for consistent hosting capacity;[46] and in the Netherlands, network development plans are based on regional-level RES development plans.[47] Another important policy interacting with distribution network planning is that on electric mobility, as lack of distribution capacity may constrain large scale adoption of electric vehicles. Further, telecommunication technologies are crucial in smart-metering and smart-grid solutions; this may result in points of contact between, on one hand, smart-metering and smart-grid plans and, on the other hand, policies on national or local ICT infrastructures. For example multiple local services, including waste collection and street control, could use the same telecommunication infrastructure set up for smart meters.

These trends call for a more comprehensive, transparent and open distribution network planning process, with greater involvement of regulators and stakeholders to some extent on the lines of mechanisms currently governing development of transmission networks. In that context as many as the distributor's objectives should be cast in terms of outputs, including for example targets on:

- Hosting capacity of embedded generation in each area of the distribution network
- Maximum total curtailment of renewable generation connected to the transmission network;
- Quality of service.

Allowed revenues could then be set against those targets and output-based incentive mechanisms designed. For examples, in exchange for a certain total revenue allowance distributors could be required to compensate embedded generators for delays in connection or for production curtailment beyond pre-defined targets[48].

The regulatory regime in Great Britain makes extensive use of reward and penalty incentives within the formulae used to calculate each DSOs´ allowed revenues. These incentives are used to encourage DSOs to achieve specific identified outputs. The main outputs which the British regulator aims to promote through the use of incentives include: developing high-quality business plans, reducing overall costs, dealing with customer complaints; customer satisfaction; engaging with stakeholders; and reducing electricity losses and disruptions.[49]

[44] This highlights the risk of stranded assets on the network. In Member States where there is no shallow connection boundary, building the network ahead of need in this manner is more difficult as it requires a contribution from the connecting customer who benefits from the investment.
[45] Discussed in Section 4.1 of the Slovenian country analysis (page 559 of this report)
[46] Discussed in Section 4.1 of the Lithuanian country analysis (on page 406 of this report)
[47] Discussed in Section 4.1 of the Netherlands country report (on page 452 of this report)
[48] Measures on this line are implemented in Germany.
[49] These incentives are discussed in section 4.4.2 of the Great Britain country report (electricity), where the sizes of each incentive is quantified.

Although the trends highlighted have by far a larger impact on the electricity industry, we would expect that a more transparent, open and comprehensive planning process be beneficial in the gas distribution sector.

We note finally that in highly fragmented distribution sectors implementation of open and audited planning processes might be unfeasible or too expensive. One possibility would be to group neighbouring distributors for the purpose of producing plans to feed into the consultation or auditing process.

We note incidentally that some crucial decisions that will shape the content of the distribution business in the future have to be coordinated among (at least, small neighbouring) distribution companies. These decisions include for example the selection of smart meter and smart grid technologies and possibly the arrangements governing operations of EV charging stations, in order to ensure interoperability of information systems and coordinated operations of interconnected networks, as well as full exploitation of scale economies. We would then expect that the same institutional process ensuring such coordination might be adapted to aggregate multiple distributors' investment plans.

5.6. Other roles of distributors

We have identified three areas of responsibilities of distributors beyond their traditional role of energy carriers.

- First, in some countries distributors play a role of facilitators of retail competition, for example through their involvement in the supplier switching process.
- Second, in some countries distributors are assigned energy efficiency responsibilities.
- Third, the increasing share of generation capacity connected to distribution networks might change the content of the distributor's activity. In a possible scenario distributors might develop into "system operators", i.e. they will control and dispatch resources connected to their networks.

At this stage we do not envisage specific implications of these activities in terms of optimal methodology to set allowed revenues and distribution tariffs. Simple financial incentive schemes may be designed to align the distributor's objectives with the regulator's in selected matters. For example fixed-price schemes to cover the costs of administering switching processes may induce distributors to minimize cost. Performance related premiums and penalties may induce distributors to actively pursue their energy efficiency objectives. The application of incentives to invest in smart metering technologies may also become more prevalent. In the electricity distribution sector in Poland for example, the regulator introduced an incentive to invest in smart metering, through allowing an increased return on capital for investments that meet the necessary requirements.[50]

Incentive-based regulation of system operations activities is also conceivable, but experience in the transmission sector indicates that striking the optimal balance between incentives and risks in the field of system operations is hard. This happens, in particular, because it is difficult to disentangle the effects on total supply costs of factors beyond and factors under the system operator's control. We would expect that the similar issues would affect the design of an incentive based mechanism of the distributors' activity as system operators.

[50] This measure is considered in Section 3.2 of the Polish electricity distribution analysis, on page 476 of this report.

However, incentivisation of selected system operator tasks, for which performance are easily measurable, have proven to be effective. For example, in some countries system operators are exposed to financial incentives to provide to market participants accurate estimates of demand for renewable production.

We would expect that the similar issues would affect the design of an incentive based mechanisms of the distributors' activity as system operators.

5.7. Metering

With the exception of the Great Britain, the prevailing organization of metering activities in Europe is based on a monopoly of gas and electricity distributors, either formally established or *de-facto*, Therefore tariff regulation of the metering activity is and will remain necessary.

We don't see any particular issues in the allocation of metering costs across consumers, since a large part of them is clearly associated with the metering point, and the remaining part, mostly related to ICT and data management, is independent from the consumer's characteristics or behaviour.

Most European regulators have mandated accounting separation of metering activities, in some cases because smart-metering costs are subject to specific treatment. We support this approach for two reasons.

- Firstly, accounting unbundling facilitates benchmarking of the cost and performance of smart-metering businesses, which we would expect to be reasonably comparable across distributors, even operating in different Member States.
- Secondly, unbundling makes it easier to reorganize metering activities in the future, in case for example data management were to be transferred from distributors to third parties.

6. Task 5 – Analysis of tariff structures of different user groups

6.1. Introduction

In this chapter we analyse and compare the electricity and gas distribution tariff structure and other aspects across EU Member States in different consumers groups. The analysis is based on the statement and the data facilitated by national regulators.

The analysis is based around the following topics:

- Role of setting the distribution tariff
- Analysis of electricity distribution Tariff
  - Tariff structure
  - Tariff components by consumer group
  - Revenues per energy consumption and connection points
  - Average network tariff by consumer group
- Analysis of Gas Distribution Tariff
  - Tariff structure
  - Tariff Components by consumer group
  - Revenues per energy consumption and connection points
  - Average network tariff by consumer group

The analysis is focused on distribution network charges, excluding connection charges for end-users and distribution tariff for embedded generators.

6.2. Role of setting the distribution tariff

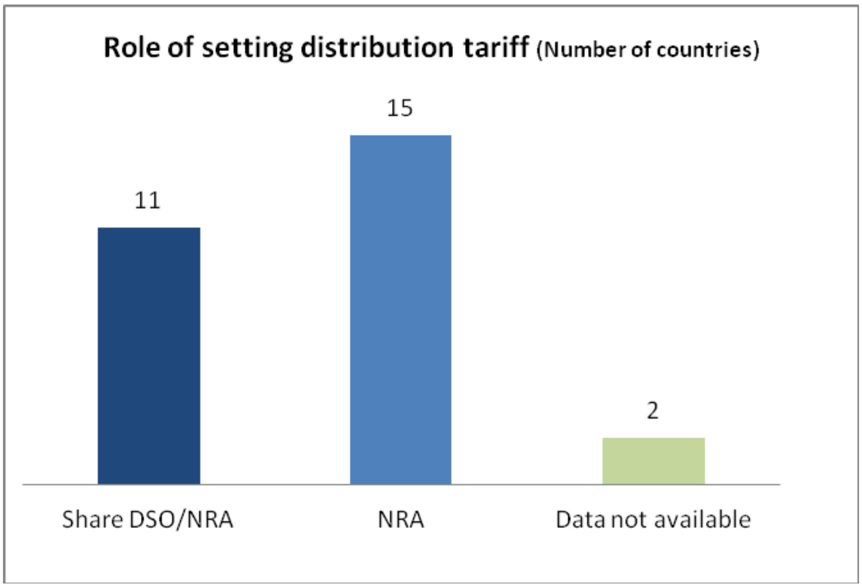
The responsibility of setting the distribution tariffs (Electricity and Gas) do not usually depend on a single actor in the EU member states. Each government through the national law (Energy act) defines the main principles of the energy sector, including the distribution business. In general two main approaches are followed:

- NRA is the main responsible. The setting of the distribution tariff, methodology, and prices for the regulatory period is an exclusive responsibility of the regulator. This approach is used in the following countries: Austria, Croatia, Czech Republic, France, Greece, Hungary, Italy, Ireland, Luxembourg, Lithuania, Portugal, Romania and Slovenia. Spain is a special case since the government is the main responsible along with the support of the regulator.
- Share of responsibilities. The NRA sets the rules, the methodology and approves tariffs or allowed revenues, while DSOs set the tariff structure and level, and the corresponding allocation between different categories of users (for instance of electricity usually by voltage levels and gas usually annual consumption). The NRA then assesses and approves the tariffs. This approach is used in the following countries: Belgium, Cyprus, Denmark, Estonia, Finland, Germany, Malta, Poland, Slovakia, Sweden and The Netherlands. In Great Britain the regulator assesses the

tariff and defines the framework of price control and revenues, but does not approve tariffs.

The figure below shows that there are 15 countries (53%) where the responsibilities of setting the distribution tariff are centralized in regulatory authorities. Other 11 countries (39%) share the responsibilities between NRAs and DSOs. There are 2 countries for which information is not available. The Annex describes in detail who is responsible of setting the distribution tariff in each Member State (MS).

Figure 1: Main responsible party for setting Distribution Tariff (Number of countries)



Source: Own elaboration on data collected from NRAs. Situation in 2013

6.3. Analysis of the Electricity Distribution Tariff

6.3.1. Tariff structure

In each EU country the tariff structure is defined by the national regulator or DSO according to certain customer segmentation. In most cases the segments are defined by voltage level, while in some countries tariffs are defined in terms of consumers' class (´household´, ´industrial´, etc.).

The main variables considered in the definition of tariff structures are:

- Voltage level. Tariff levels are defined for specific voltage ranges at the point of connection to the distribution grid. Usually there are three levels: High Voltage (higher than 36 kV), Medium Voltage (between 1-36 kV) and Low Voltage (less than 1 kV). In some countries the distribution networks only operate Medium Voltage and Low Voltage networks.
- Contractual capacity/power. Tariff levels are defined for ranges of contractual power according to users demand profile.
- Consumer group. Users are segmented according to their characteristics. Customer categories are often differentiated by the type of user (Small house, Household,

Farm, Business Customers, Small Industrial, Public lighting systems, Public recharging of electric vehicles, etc.)

- Metering system. Tariff levels are designed according to the capabilities of metering devices to obtain data (Smart metering: Time of use consumption, Peak demand power, etc.)
- Annual consumption. Tariff levels are sorted out according to different intervals or bands of annual consumption (Kwh/year).
- Geographic zone. In some countries the geographic zone is one of the variables used to define tariff levels.

In the majority of the EU Member States (24 of 25 with available data), the main variable used to define the tariff categories is the **voltage level.** In some countries such as Denmark, Estonia, Romania and Slovenia this is the only variable used to allocate users to a given tariff category.

In other countries both the **voltage level** and the **contractual power are the main variables for identifying tariff categories**. This happens for example in Austria, France, Greece, Hungary, The Netherlands, Poland, Portugal and Spain.

Other countries such as Croatia, Cyprus, Czech Republic, Italy, Lithuania and Slovakia also have tariffs defined by **voltage level** and **specific consumers groups** such as Households, Small Industrial, Large Industrial, etc. In the Czech Republic, Finland, Ireland and Malta the tariffs are defined by **voltage level**, specific **consumers groups** and **contractual capacity**.

It is as also important to highlight that **metering systems** are one of the criteria in use in some countries in order to define the tariff segmentation. Some MS that use this variable are Austria, Croatia, France, Germany, Greece, Ireland, Luxembourg and Great Britain.

One additional component that is taken into consideration in a limited number of countries is the **annual energy consumption** as in the case of Finland (i.e.: Tariff L1. House with electrical heating in every room, 3x25 A, usage 18000 kWh/annum) and Malta.

Finally in Sweden, the methodologies for setting the tariff vary considerably between the different DSOs as long as it is non-discriminatory and objective.

The following table describes the variables involved in the definition of the tariff levels for each country.

Table 22: Key variables used in the definition of electricity distribution tariffs categories in EU countries

	Tariff Structure				
Country	Voltage level	Annual Energy consumption	Consumer group	Metering system	Contractual capacity/power
Austria	X			X	X
Belgium	N.A	N.A	N.A	N.A	N.A
Bulgaria	N.A	N.A	N.A	N.A	N.A
Croatia	N.A		X	X	
Cyprus	X		X		
Czech Republic	X		X		X
Denmark	X				
Estonia	X				
Finland	X	X	X		X
France	X			X	X
Germany	X			X	
Greece	X			X	X
Hungary	X				X
Ireland	X		X	X	X
Italy	X		X		
Latvia	N.A	N.A	N.A	N.A	N.A
Lithuania	X		X		
Luxembourg	X			X	
Malta	X	X	X		X
Netherlands	X				X
Poland	X				X
Portugal	X				X
Romania	X				
Slovakia	X		X		
Slovenia	X				
Spain	X				X
Sweden	Depends on DSO				
Great Britain	X		X	X	X
Total countries	23	2	10	8	13

Source: Own elaboration on data provided by NRAs with reference to the year. Situation in 2013

6.3.2. Tariff components

The analysis illustrates the identification of the electricity tariff components and a comparison of component weight share across EU Member States for the following consumer groups:

- Household user connected to a low voltage network with an annual consumption of 3,5 MWh and 6 kW of contractual power.

- Small Industrial user connected to a low voltage network, an annual consumption of 50 MWh and 35 kW of contractual power. (In The Netherlands this contractual power -35KW- is part of Household tariff)
- Large industrial user with an annual consumption of 24000 MWh, 7000 use hours and 4000 kW of contractual power.

The most common components in Electricity networks are:

- Fixed component: In some countries it is known as standing charge or service charge by connection point/costumer. (€/day, €/month, €/year).
- Capacity component: component to charge the users for the availability to use a maximum power. Usually for the household user the maximum power is controlled thought a circuit breaker. For the industrial user the maximum power is controlled and metered through peak demand meters (maximeters). In most countries, the user will face considerable charges, if they exceed this maximum contractual capacity (€/kW).
- Active Energy component: charge for the actual usage of energy. It is the volumetric component of the tariff. In some countries it is known as commodity or variable charge (€/kWh).
- Reactive energy/power component: charge for reactive energy (€/ KVArh).
- Loss energy component: it is a per energy component used to charge the technical distribution network losses. In most of the countries the losses are included in the active energy component.

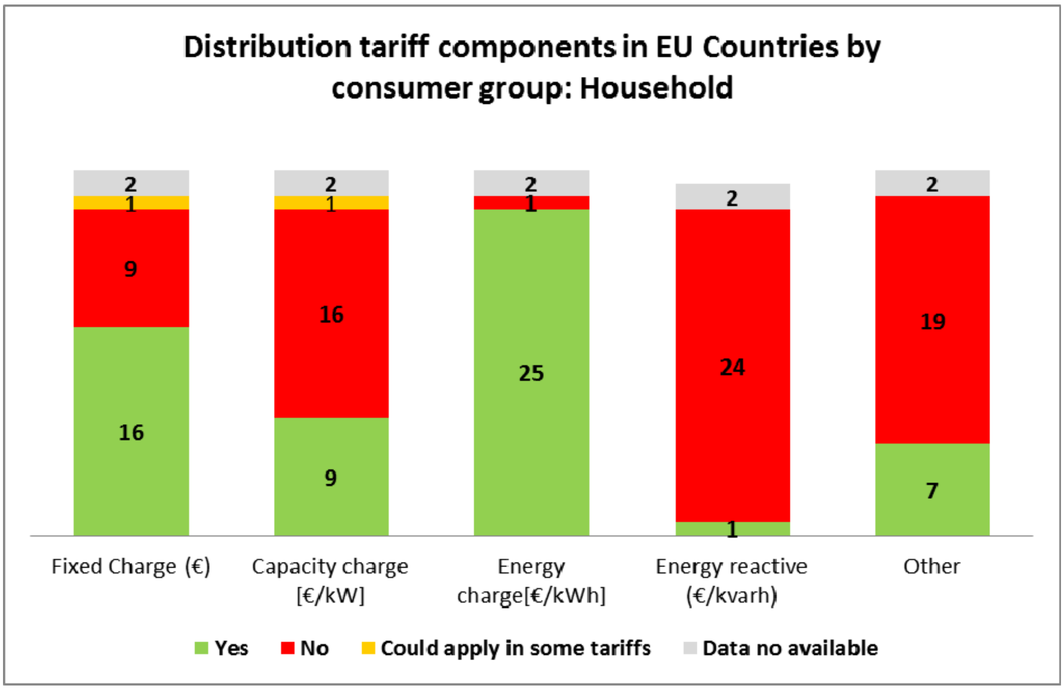
Components of electricity distribution tariffs were analysed according to the information provided by regulators as well as publicly available information. Additionally, for countries where data are available, the weight of each component for each consumer group along with other relevant aspects are shown.

6.3.2.1. Household consumer group

Identification of tariff components

The following figure refers to Households consumer groups and describes for each tariff components, in how many EU Member States it is applied.

Figure 2: Distribution Tariff components in Household (Number of countries)[51]



Source: Own formulation based on data provided by national regulators.
Situation in 2013. Data from Bulgaria and Latvia are not available.

The next table details the tariff components defined for household consumers across EU member states.

[51] For countries which fall into the category of ´could apply in some tariffs´, this refers to the situation whereby some (but not all) of the tariffs used in that country include the particular tariff component under consideration.

Table 23: Distribution tariff components identified by country for Household consumers

Country	Fixed Charge	Capacity charge	Energy charge	Energy reactive	Other
Austria	Yes	No	Yes	No	No
Belgium	Yes	No	Yes	No	No
Bulgaria	N.A	N.A	N.A	N.A	N.A
Croatia	No	No	Yes	No	Yes, Metering
Cyprus	Yes	No	Yes	No	No
Czech Republic	Yes	No	Yes	No	No
Denmark	Yes	No	Yes	No	No
Estonia	No	Yes, it's possible. There are two options: Capacity + Energy or Energy	Yes	No	No
Finland	No	Yes	Yes	No	No
France	Yes	Yes	Yes	No	No
Germany	Yes	No	Yes	No	No
Greece	No	Yes	Yes	No	No
Hungary	Yes	No	Yes	Possible if the meter installed can measure the reactive power.	Yes, Loss charges
Ireland	Yes	No	Yes	Yes	No
Italy	Yes	Yes	Yes	No	Yes, Metering
Latvia	N.A	N.A	N.A	No	N.A
Lithuania	Yes, it is Possible	No	Yes	No	No
Luxembourg	Yes	No	Yes	No	Yes, Metering
Malta	Yes	No	Yes	No	No
Poland	Yes	No	Yes	No	Yes, subscription fee (Metering)
Portugal	No	Yes	Yes	No	No
Romania	No	No	Yes	No	No
Slovakia	No	Yes	Yes	No	Yes, distribution losses
Slovenia	No	Yes	Yes	No	No
Spain	No	Yes	Yes	No	Yes, Metering
Sweden	Yes	No	Yes	No	No
The Netherlands	Yes	Yes	No	No	No
Great Britain	Yes	No	Yes	No	No

Source: Own elaboration on information provided by national regulators included in country reports (country report Table 3: Tariff components, customers and revenues per customer class).
N.A: Data not available.

In the case of household clients, most countries apply a fixed (standing) charge (16), while a lower number of countries apply a capacity charge (9). Fixed charges (a flat fee for a period of time: day, month, year) could depend on different parameters as shown below.

For example in Austria, for a Household user (Tariff 7) a fixed (standing annual) charge between 13,80 and 23,52 €/year is charged depending on the zone. In Denmark or Italy, all consumers pay a subscription or fixed charge that is equal for all the consumers in the same class. In the Czech Republic there is a fixed per capacity reservation component equal for all consumers in the same class (CZK/A of circuit breaker and month). In Hungary household consumers are charged a Basic charge that includes a per connection component for all consumers in the same class. In Luxembourg the residential customers with LV SLP (Non metered Low Voltage Synthetic Load Profile) only pay 2€ per month as a fixed charged.

Other countries with fixed components include: Belgium, Cyprus, Denmark, France, Germany, Italy, Malta, Ireland, Luxembourg, Poland, Sweden, The Netherlands and Great Britain.

The capacity charge depends on the maximum power contracted and billed to end-users. Users may pay a kW/day, kW/month or kW/year fee. For example in Spain household consumers usually have the 2.0A tariff which is for a contracted power lower than 10kW (€/kW/year).

This capacity component applies in Finland, France, Greece, Italy, Portugal, Slovakia, Slovenia, Spain and The Netherlands. In Estonia the capacity charges could apply or not depending on DSO.

Usually in the countries where the user pays for a capacity charge, they do not pay for a fixed charge, with the exception of France, Italy, The Netherlands and Sweden. In almost all the countries the variable cost of distribution network is charged as an energy component (25) with the exception of The Netherlands.

In some countries (12) such as Austria, Croatia, Czech Republic, Ireland, Lithuania, Portugal, Poland, Spain and Great Britain there could be more than one energy component depending on the time of use. These kinds of tariffs encourage consumers to use energy at off-peaks time which reduces the energy used in peak periods, balancing the grid consumption.

For example in Austria There are four time blocks (winter and summer, both split in a peak and off-peak time) and 15 zones. In Ireland, Croatia, Estonia or Lithuania the energy component could have one or two time zones. In Spain, the energy component of tariff 3.1 has three time zones (3P).

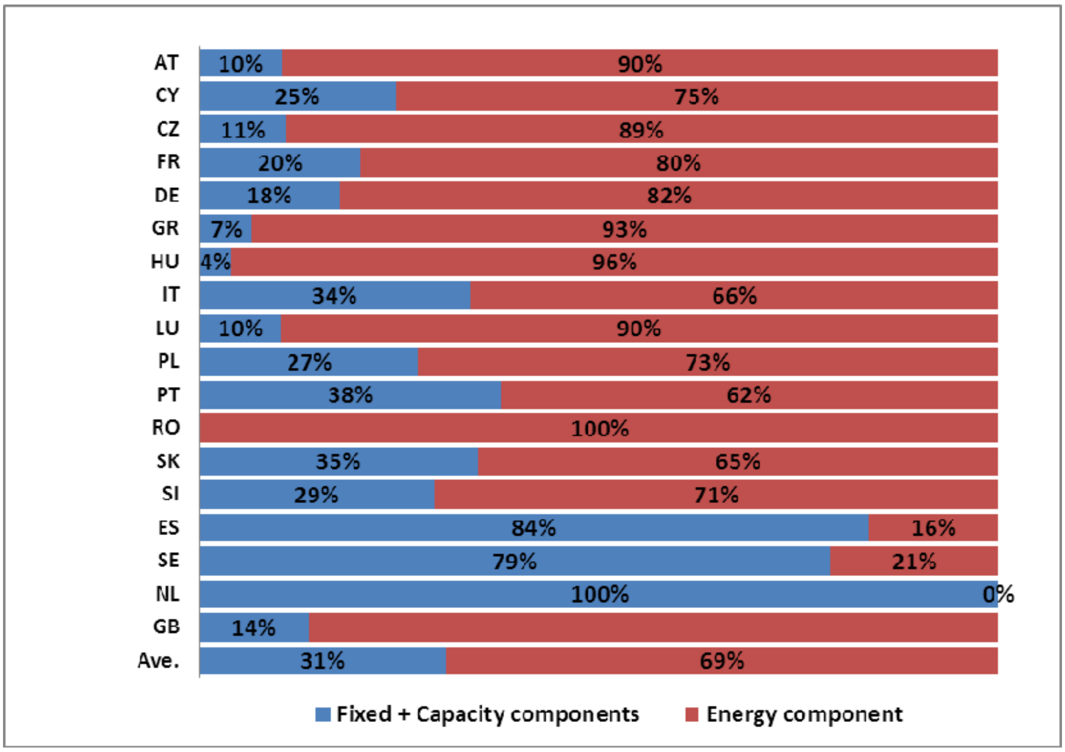
The reactive energy component is less common in Household consumers (1 countries). Although the component is defined by the regulator, it is hardly ever put into practice. For example in Hungary it only applies to consumers, if the meter installed can measure the reactive power (this charge represents only a very small part of the DSO's income). In Spain the reactive component is defined and published by the regulator, but in practice it is not charged to household consumers. In Ireland a reactive energy charge applies to this consumer group.

In the majority of the countries (17) there are no "other" distribution tariff components for household consumers. However in Hungary and Slovakia, there is a Loss Distribution component which is part of the network tariff. In Croatia, Spain, Luxembourg, Poland and Italy, there is a separate tariff component which charges for the use of metering devices.

Weight of tariff components

The following figure shows a comparison of weights of tariff components across EU member states for Household consumers. For the calculation, the following components were considered: fixed charge, capacity charge and active energy charge.

Figure 3: Distribution Tariff component weight in Households



Source: Own elaboration on Fixed charges, Capacity charges and Energy charges values facilitated by national regulators. Data of Belgium, Bulgaria, Croatia, Denmark, Estonia, Ireland, Latvia, Lithuania and Malta are not available.
Household consumer with an annual consumption of 3500 kWh connected to the low voltage grid and 6 KW of contracted capacity. Situation in 2013.
Details on values of each component by country is summarised in “Annex 5: Breakdown of electricity network annual charges by country – customer types”.

For a Household consumer, the average active energy component across EU member states (19 countries with data available) is above 69% of the total.

In most of countries, the weight of the energy component is above 60% including Austria, Cyprus, Czech Republic, France, Germany, Greece, Hungary, Italia, Poland, Portugal, Slovakia, Slovenia and Great Britain. In Romania the network is recovered only by an energy component.

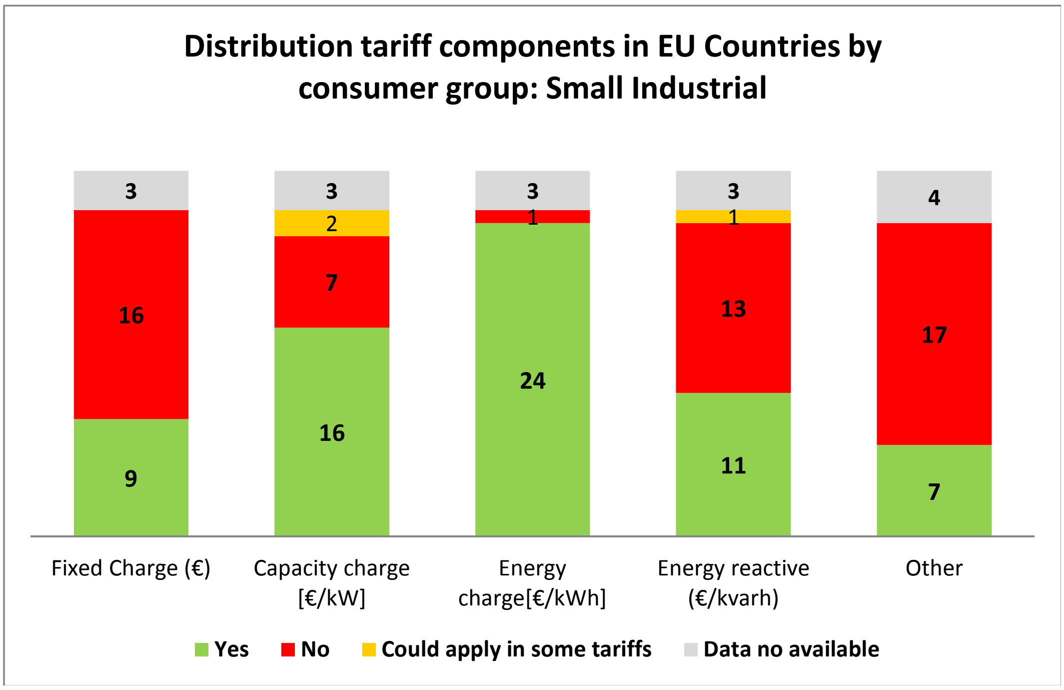
On the other hand Finland presents an even distribution of cost recovery between the energy and fixed components, while a few countries including Spain and Sweden the fixed or capacity component is dominant and around or above 80% In the Netherlands the totality of costs is charged through the capacity component for household consumers.

6.3.2.2. Small industrial consumers

Identification of tariff components

The following figure refers to the Small Industrial consumer group and describes in how many countries a specific tariff component is applied.

Figure 4: Distribution Tariff components in Small Industrial (Number of countries)



Source: Own elaboration based on questionnaires and country report with data provided by national regulators.
Situation in 2013. Data for Belgium, Bulgaria and Latvia are not available for this consumer group.

The next table shows details of the tariff components defined for small industrial consumer across EU Member States.

Table 24: Distribution tariff components identified by country for Small Industrial consumer

Country	Fixed Charge	Capacity charge	Energy charge	Energy reactive	Other
Austria	No	Yes	Yes	N.A	No
Belgium	N.A	N.A	N.A	N.A	N.A
Bulgaria	N.A	N.A	N.A	N.A	N.A
Croatia	No	Yes	Yes	Yes	Yes, Metering
Cyprus	Yes	No	Yes	No	No
Czech Republic	No	Yes	Yes	Yes	No
Denmark	Yes	No	Yes	No	No
Estonia	No	Yes, it's possible. There are two options: Capacity + Energy or Energy	Yes	Yes	N.A
Finland	No	Yes	Yes	No	No
France	Yes	Yes	Yes	Yes	No
Germany	No	Yes	Yes	Yes	No
Greece	No	Yes	Yes	No	No
Hungary	Yes	No	Yes	Yes	Yes, Loss charges
Ireland	Yes	No	Yes	Yes	No
Italy	Yes	Yes	Yes	No	Yes, Metering
Latvia	N.A	N.A	N.A	N.A	N.A
Lithuania	No	Yes	Yes	No	No

Country	Fixed Charge	Capacity charge	Energy charge	Energy reactive	Other
Luxembourg	No	Yes	Yes	No	Yes, Metering
Malta	Yes	No	Yes	Yes	No
Poland	No	Yes	Yes	No	Yes, subscription fee (Metering)
Portugal	No	Yes	Yes	Yes	No
Romania	No	No	Yes	No	No
Slovakia	No	Yes	Yes	No	Yes, distribution losses
Slovenia	No	Yes	Yes	No	No
Spain	No	Yes	Yes	Yes	Yes, Metering
Sweden	Yes	No	Yes	No	No
The Netherlands	No	Yes	No	Yes	No
Great Britain	Yes	Yes. It can apply if the small industrial consumer if they elect to move to HH settlement.	Yes	Yes. It can apply if the small industrial consumer if they elect to move to HH settlement.	No

Source: Own elaboration based on questionnaires and country report with data provided by national regulators.
N.A: Data not available.

Most countries apply a capacity charge (16) rather than a fixed charge (9) contrary to what happens with household clients. The capacity charge is applied in Austria, Croatia, Czech Republic, Finland, France, Germany, Greece, Italy, Lithuania, Luxembourg, Poland, Portugal, Slovakia, Slovenia, Spain and The Netherlands. A fixed component is applied in Cyprus, Denmark, France, Hungary, Ireland, Italy, Malta, Sweden and Great Britain. In France and Italy both components could apply for small industrial consumers. In Great Britain both components can apply if the customer chooses to move to smart metering (supply points with half hourly meters). In Estonia the capacity charges could apply or not depending on DSO.

In all the countries with available information there is an energy component for small industrial consumers. In 15 countries a time-of-use distribution tariff is applied in one way or another. (See Annex 4 Summary of time-of-use differentiation in electricity distribution tariff by consumer group)

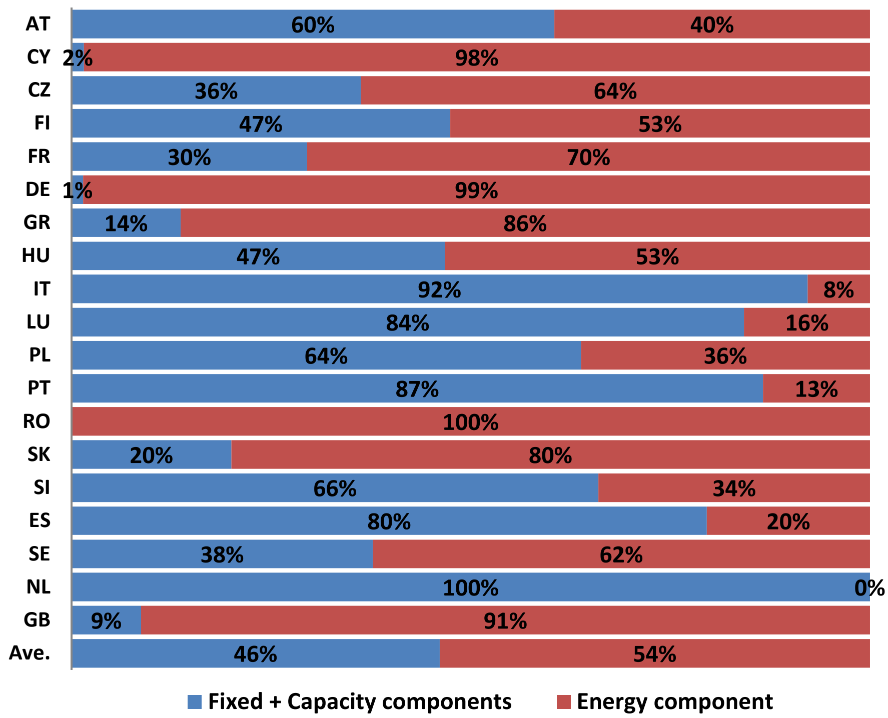
The reactive energy component for small industrial users is more common than with household clients. This component exists in 12 countries of the 25 where this kind of data is available. Those are Croatia, Czech Republic, Estonia, France, Germany, Hungary, Ireland, Malta, Portugal, Spain and The Netherlands and Great Britain. In Great Britain the reactive charge can apply to small customers if they choose to move to smart metering (supply points with half hourly meters). For Austria, Cyprus, Denmark, Finland, Greece, Italy, Lithuania, Luxembourg, Poland, Romania, Slovakia, Slovenia and Sweden there is no evidence on the use of this component.

In some countries there are also additional distribution tariff components (7). There is a Loss Distribution component in Hungary and Slovakia. In Croatia, Spain, Luxembourg, Italy and Poland, there is a tariff component which charges for the use of metering devices.

Weight share of tariff components

The following figure shows a comparison of weight of tariff components across EU Member States for small industrial consumers. For the calculation, the following components were considered: fixed charge, capacity charge and active energy charge.

Figure 5: Distribution Tariff component weight in Small Industrial



Source: Own elaboration on data provided by national regulators on fixed charges, capacity charges and energy charges, Data for Belgium, Bulgaria, Croatia, Denmark, Estonia, Ireland, Latvia, Lithuania and Malta are not available.
Small industrial consumer with an annual consumption of 50000 kWh connected to the low voltage grid and contracted capacity of 35 KW. Situation in 2013
Details for each component by country is summarised in "Annex 5: Breakdown of electricity network annual charges by country – customer types"

For a small Industrial consumer, the average active energy charge (19 countries with data available) is about 54% of the total charges for distribution activities, while non-volumetric charges (fixed or capacity component) amount to around 46%. For this type of consumer the capacity or/and fixed component have a higher weight when compared with household consumers.

The weight of the active energy charge is higher than 85% of the total expenditure in 6 out of 19 countries with available data. These countries are Cyprus, Germany, Greece, Romania, Slovakia and Great Britain. Romania is a special case where only an energy component applies.

In other countries distribution network costs are spread more evenly between different tariff components).These countries are: Czech Republic, Finland, France, Hungary and Sweden.

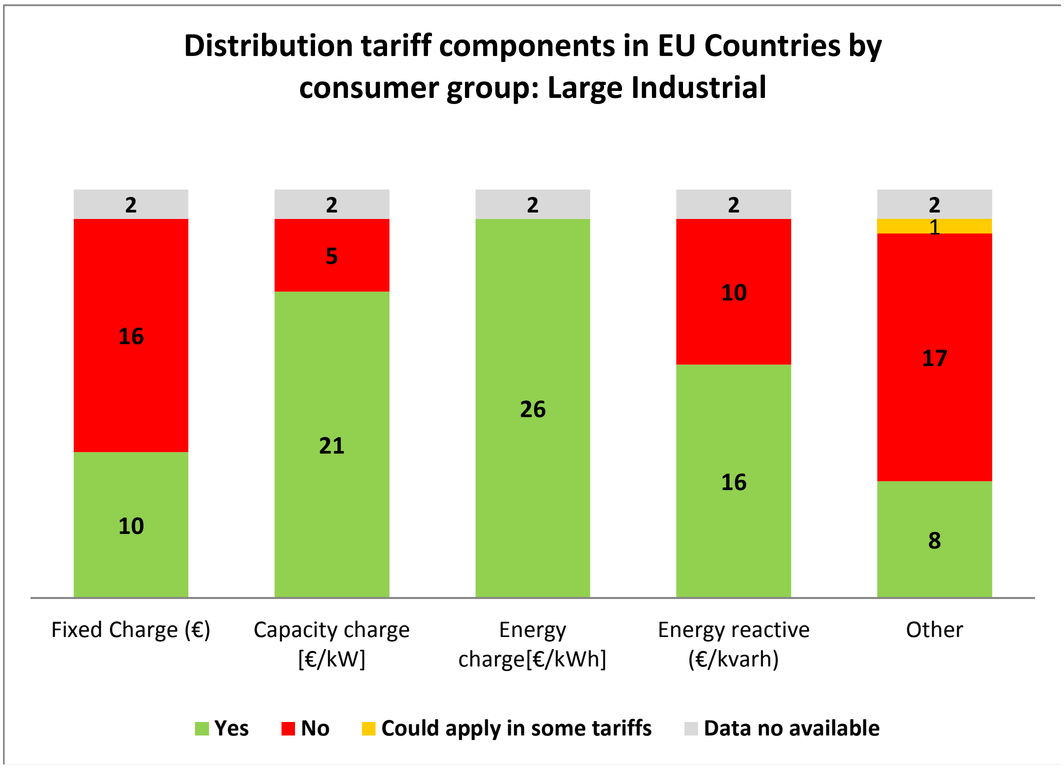
On the other hand, in some countries such as Austria, Italia, Luxembourg, Poland, Portugal, Slovenia, Spain and The Netherlands the fixed and/or capacity charge (Contracted Power) represent between 60% and 100% of the distribution network tariff charges.

6.3.2.3. Large industrial consumers

Identification of tariff components

The following figure refers to the large industrial consumer group and describes in how many countries a specific tariff component is applied.

Figure 6: Distribution Tariff components for Large Industrial customers (Number of countries)



Source: Own elaboration based on questionnaires and country report with data provided by national regulators.
Situation in 2013. Data for Belgium, Bulgaria and Latvia are not available for this consumer group.

The next table details the tariff components defined for large industrial consumer across EU Member States.

Table 25: Distribution tariff components by country for Large Industrial consumers

Country	Fixed Charge	Capacity charge	Energy charge	Energy reactive	Other
Austria	No	Yes	Yes	No	No
Belgium	Yes	Yes	Yes	Yes	No
Bulgaria	N.A	N.A	N.A	N.A	N.A
Croatia	No	Yes	Yes	Yes	Yes, Metering
Cyprus	Yes	No	Yes	No	No
Czech Republic	No	Yes	Yes	Yes	No
Denmark	Yes	No	Yes	No	No
Estonia	No	Yes	Yes	Yes	No
Finland	No	Yes	Yes	Yes	No
France	Yes	Yes	Yes	Yes	No
Germany	No	Yes	Yes	Yes	No
Greece	No	Yes	Yes	Yes	Possible
Hungary	Yes	Yes	Yes	Yes	Yes, Loss charges
Ireland	Yes	Yes	Yes	Yes	No
Italy	Yes	Yes	Yes	No	Yes, fees related to activity measurement
Latvia	N.A	N.A	N.A	N.A	N.A
Lithuania	No	Yes	Yes	No	No
Luxembourg	No	Yes	Yes	No	Yes, Metering
Malta	Yes	No	Yes	Yes	No
Poland	No	Yes	Yes	Yes	Yes, subscription fee (Metering)
Portugal	No	Yes	Yes	Yes	No
Romania	No	No	Yes	No	No
Slovakia	No	Yes	Yes	No	Yes, distribution losses
Slovenia	No	Yes	Yes	Yes	No
Spain	No	Yes	Yes	Yes	Yes, Metering
Sweden	Yes	No	Yes	No	No
The Netherlands	No	Yes	Yes	No	No
Great Britain	Yes	Yes	Yes	Yes	Yes, Excess Capacity charge

Source: Own elaboration based on questionnaires and country report with data provided by national regulators.
N.A: Data not available.

In most countries (21) with available information the capacity charge for large industrial consumers applies. Cyprus, Denmark, Malta, Romania and Sweden are exceptions. Malta only has a fixed charge (€/year) and energy charges for voltage levels and Romania only has a volumetric component (€/kWh). In Denmark larger consumers pay a subscription fee that is equal for everyone in the same class.

There are 6 countries where both a fixed charge and a capacity charge apply. These countries are Belgium, France, Hungary, Ireland, Italy and Great Britain.

As in the small industrial consumer group, all the countries have an energy component. In 15 of 26 countries, a time-of-use distribution tariff is applied (See Annex 4. Summary of time-of-use differentiation in electricity distributions tariff by consumer group).

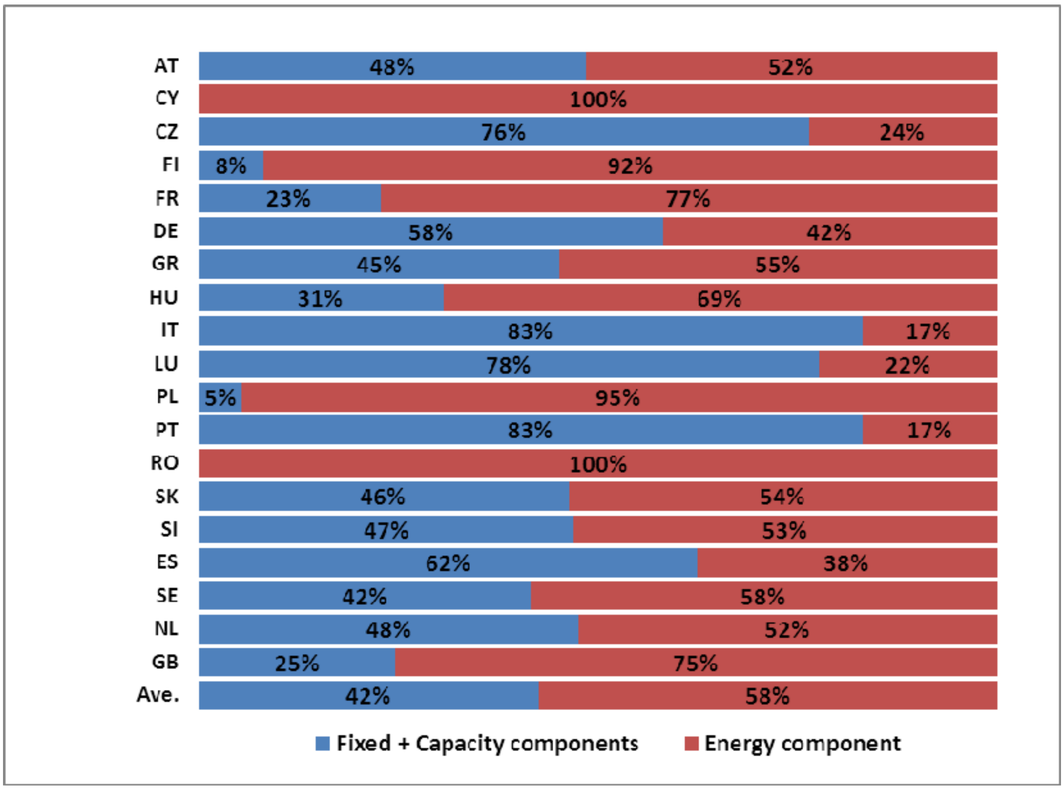
Reactive energy charges are applied in the majority of countries (16). Exceptions occur in some countries, such as Austria, Cyprus, Denmark, Greece, Luxembourg, Romania, Slovakia, Slovenia and Sweden. In the Netherlands, it depends on the DSO criteria.

There are additional distribution tariff components in some countries (8). Those are the same countries and components that are applied in small consumer clients. In Great Britain there is an exceeded capacity charge (per day) for consumer with half hourly meter installed (Typical Industrial-High Voltage).

Weight of tariff components

The following figure shows a comparison of weights of tariff components across EU Member States for large industrial consumers according to the data facilitated by the national regulators. For the calculation, the following components were considered: fixed charge, Capacity charge and Active energy charge.

Figure 7: Distribution Tariff component weight for Large Industrial



Source: Own elaboration based on data provided by national regulators for Fixed charges, Capacity charges and Energy charges.
Large industrial customer with an annual consumption of 24000 MWh and 7000 use hours connected to the medium voltage grid and 4000 KW of contracted capacity. Situation in 2013
Detailed values of each component by country is summarised in “Annex 5: Breakdown of electricity network annual charges by country – customer types”

For a large industrial consumer, the capacity or fixed component of the distribution tariff has an average weight of approximately 42% across EU Member States (19 countries with data available). In some countries such as Czech Republic, Germany, Italy, Luxembourg, Portugal and Spain the weight of fixed and capacity components are at least 60% of network tariff charges.

In a majority of countries, network costs are recovered more through energy components than through fixed or capacity components. Some countries with this characteristic are Austria, Cyprus, Finland, France, Greece, Hungary, Poland, Slovakia, Slovenia, Sweden, The Netherlands and Great Britain. In Romania all network costs are charged through an energy component.

6.3.3. Allowed revenues for distribution activities

The objective of this section is to provide an overview of the allowed revenues for electricity distribution activities across EU member states Comparison of ratios of allowed distribution revenues and their activities is a complex task, mainly because in different countries DSOs do not provide an identical and homogenous product/service, neither this is delivered under comparable conditions.

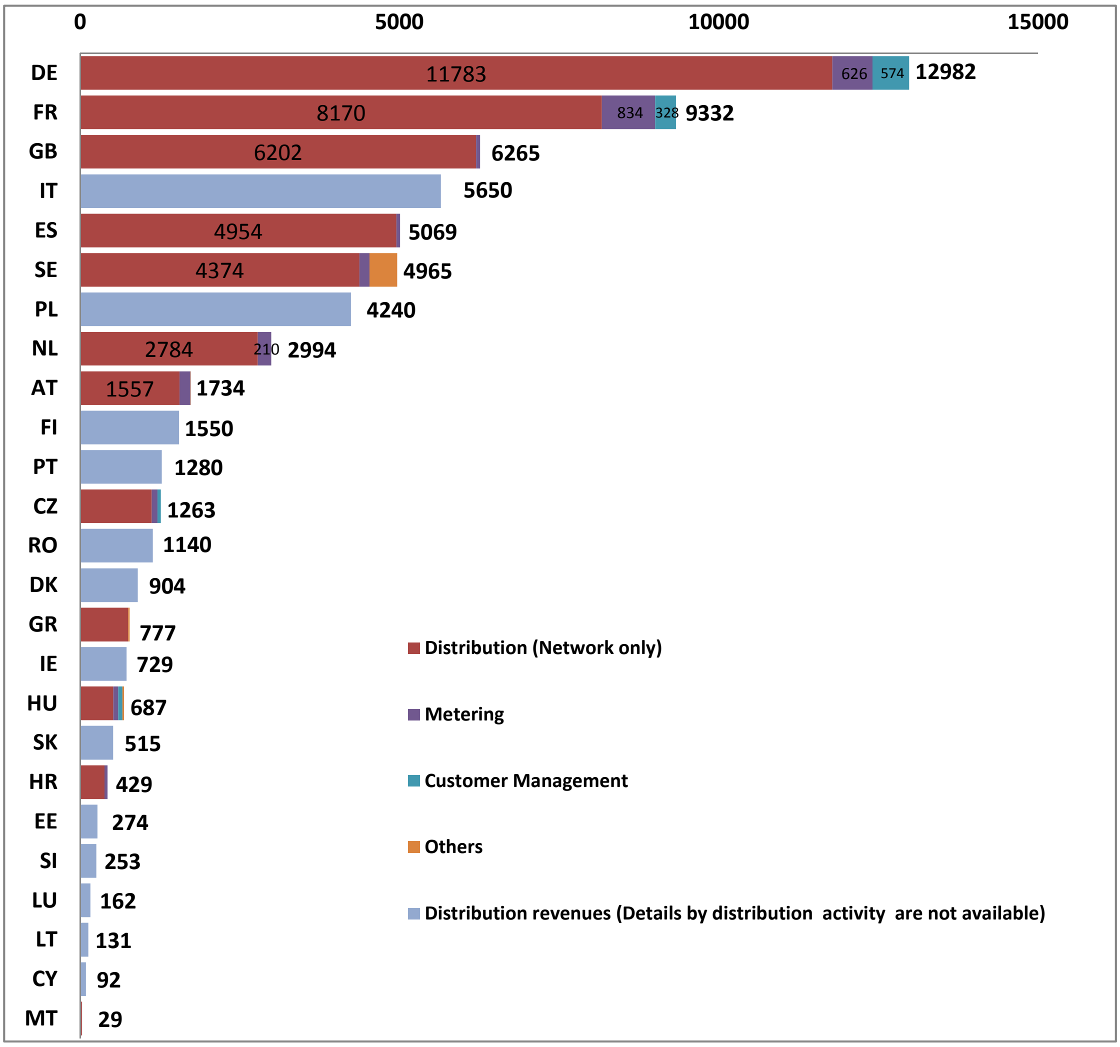
The services delivered by DSOs across Europe are different in many respects. Different DSOs are required to provide different qualities of service; they serve different loads, accommodate different proportions of distributed generation and do not operate under comparable conditions in terms of, for example, density of population connected, and geographical constraints with an impact on network design and operations.

In this context, the indicators presented in this section serve to show reference values and an overview of electricity distribution revenues across EU Member States, but do not attempt to identify differences in efficiency or best practices.

The following figure shows the total electricity distributions revenues (Excluding transmission cost, taxes and levies) and a breakdown of the cost of different distribution activities across EU Member states in 2013 where data are available.

The analysis is based on the data provided by national regulators.

Figure 8: Electricity Distribution revenues across EU Member States in 2013. (Millions of Euros)

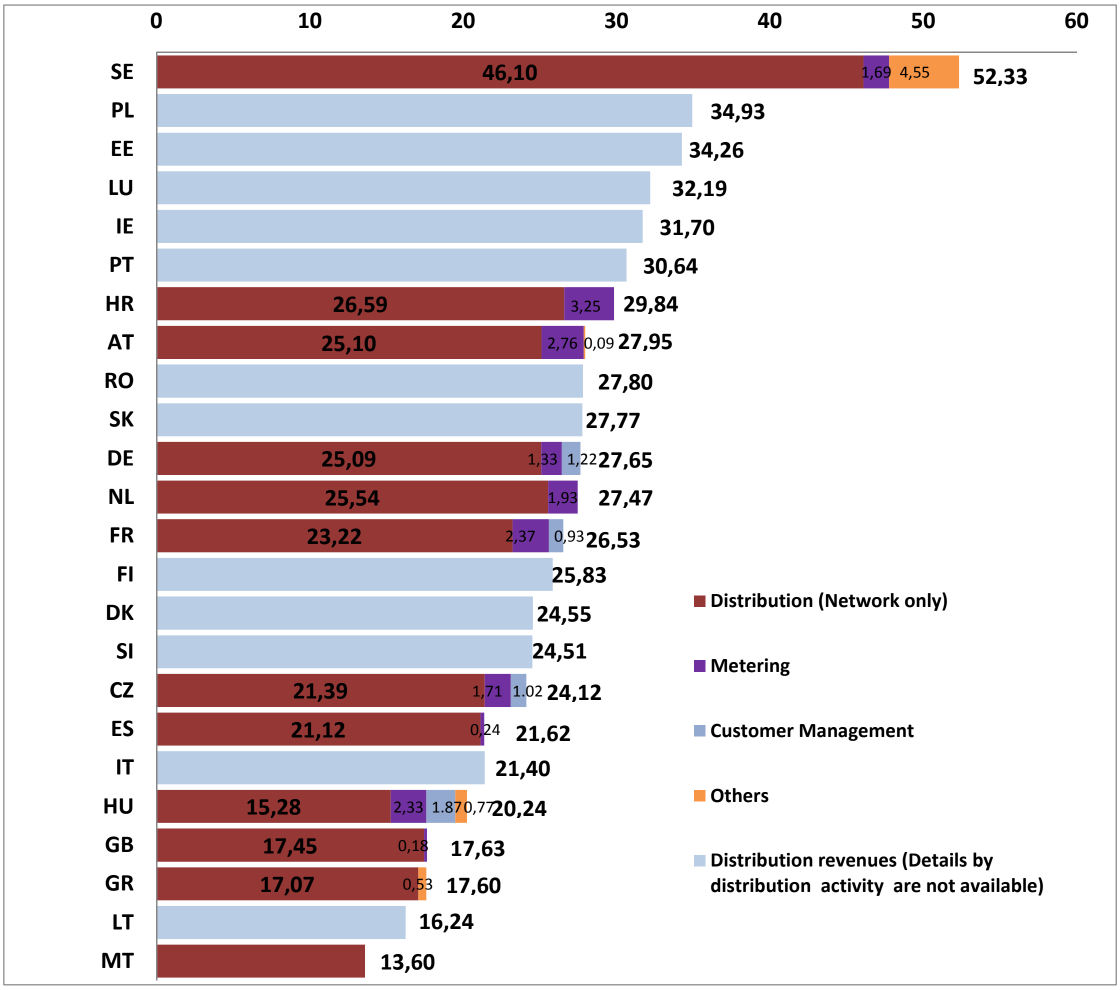


Source: Own elaboration on data provided by National Regulators.
Total Distributions revenues include: Distributions revenues (Network only), Metering and Customer Management. Cost of distribution losses is not included.
Details and comments on the values for each country are summarised in Annex 7. Allowed electricity distribution revenues across EU Member states in 2013
Spain: Data of allowed distribution revenues for 2014.
Germany: analysis based on data of DSO under the responsibility of Bundesnetzagentur. DSOs with fewer than 100000 final customers are predominantly under the responsibility of the regulatory authorities of the German federal states. The share of revenues of DSOs regulated by BNetzA from total revenues is roughly 85-90% and can vary from year to year. The data is based on planned values. The revenues are still provisional as the final formal approval of revenues including volatile costs and permanent not controllable costs is only commenced with approval of revenues in 3rd regulatory Period starting from 2019. Revenue data do not contain revenues for elements that are not within network charges but are passed through by the DSO (e.g. concession fee, renewable energy support levy).Total allowed revenues have been reduced by the amount of upper grid charge to avoid double counting of costs (and inclusion of transmission costs in revenue figures).

According to the data available for 25 EU member states, the electricity distribution allowed revenues in 2013 were approximately 63 billion €. Germany was the country with the higher share, followed by France, Great Britain, Italy, Spain and Sweden.

The following figure shows the total electricity distribution revenues (Excluding transmission cost, taxes and levies) per energy delivered (€/ MWh) across EU Member states in 2013[52].

Figure 9: Electricity Distribution revenues per energy delivered across EU Member States in 2013. (Euros per MWh)



Source: Own elaboration on data provided by National Regulators.
Total Distributions revenues include: Distributions revenues (Network only), Metering and Customer Management. Cost of distribution losses is not included.
Details and comments on the values for each country are summarised in Annex 7. Allowed electricity distribution revenues across EU Member states in 2013.
Spain: Data of allowed distribution revenues for 2014.
Germany: analysis based on data of DSO under the responsibility of Bundesnetzagentur. DSOs with fewer than 100,000 final customers are predominantly under the responsibility of the regulatory authorities of the German federal states. The share of revenues of DSOs regulated by BNetzA from total revenues is roughly 85-90% and can vary from year to year. The data is based on planned values. The revenues are still provisional as the final formal approval of revenues including volatile costs and permanent not controllable costs is only commenced with approval of revenues in 3rd regulatory Period starting from 2019. Revenue data do not contain revenues for elements that are not within network charges but are passed through by the DSO (e.g. concession fee, renewable

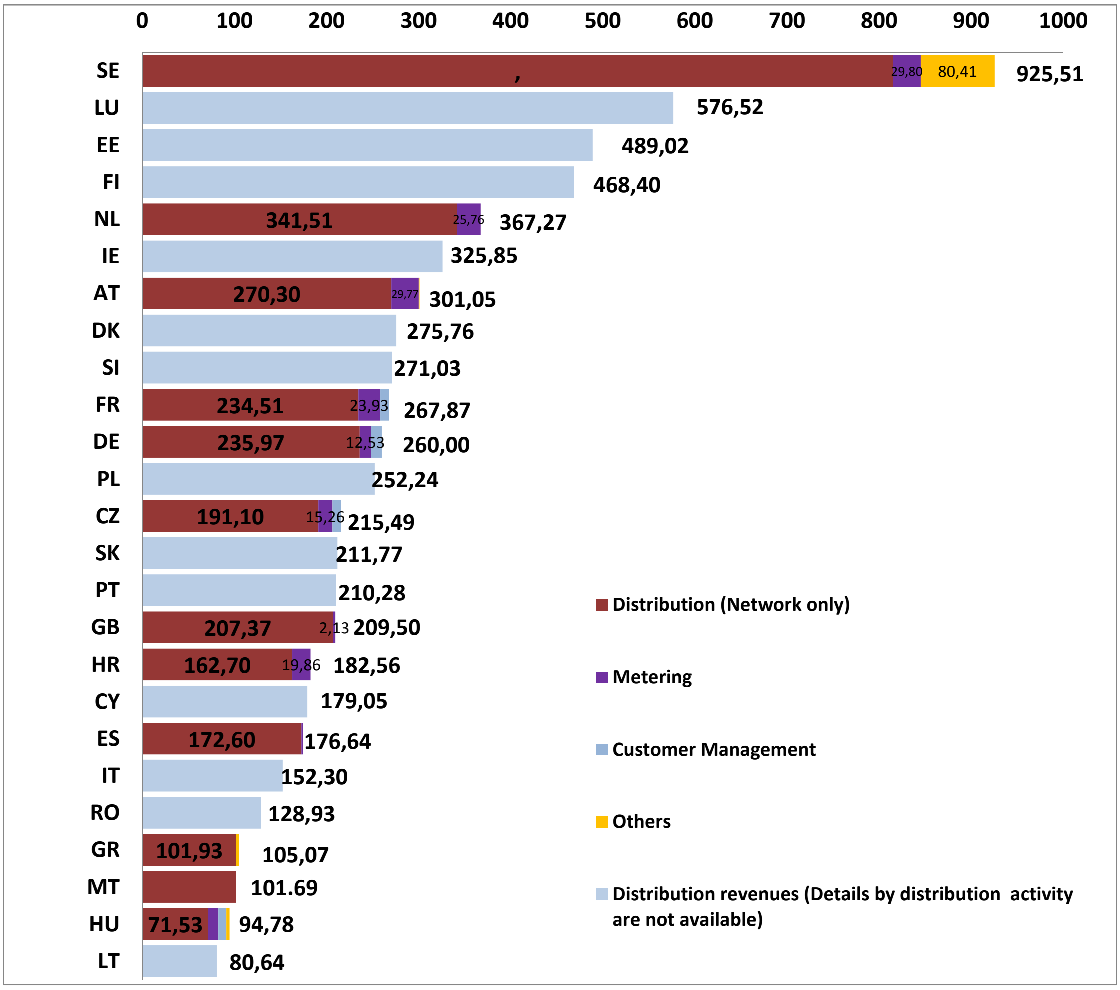
[52] In some countries as Greece, Ireland, Italy, Portugal, Spain the cost of distribution losses are charged in retail prices and are not included in distribution allowed revenues. In other countries such as Cyprus, Denmark, Estonia, France, Germany, the Czech Republic, Hungary and the Netherlands the distributions losses are include in the total allowed revenues of DSO´s. In any case, revenue ratios are calculated excluding distribution losses according to available data provided by national regulators.

energy support levy).Total allowed revenues have been reduced by the amount of upper grid charge to avoid double counting of costs (and inclusion of transmission costs in revenue figures).

The analysis of average distribution revenues by distributed energy shows that the country with higher revenue per MWh is Sweden (52,33 €/MWh), followed by Poland (34,93 €/MWh), Estonia (34,26 €/MWh) and Luxembourg (32,19 €/MWh). On the other hand the countries with less allowed revenues per MWh are Malta (13,60 €/MWh), Lithuania (16,24 €/MWh), Greece (17,60 €/MWh) and Great Britain (17,63 €/MWh).

The following figure shows the total electricity distributions revenues (Excluding transmission cost, taxes and levies) per connection point (€/connection point) across EU Member states in 2013.

Figure 10: Distribution revenues per connection point across EU Member States in 2013. (Euros per connection point)



Source: Own elaboration on data provided by National Regulators.
Total Distributions revenues include: Distributions revenues (Network only), Metering and Customer Management. Cost of distribution losses is not included.
Details and comments on the values for each country are summarised in Annex 7. Allowed electricity distribution revenues across EU Member states in 2013.
Spain: Data of allowed distribution revenues for 2014.
Germany: analysis based on data of DSO under the responsibility of Bundesnetzagentur. DSOs with fewer than 100000 final customers are predominantly under the responsibility of the regulatory authorities of the German federal states. The share of revenues of DSOs regulated by BNetzA from total revenues is roughly 85-90% and can

vary from year to year. The data is based on planned values. The revenues are still provisional as the final formal approval of revenues including volatile costs and permanent not controllable costs is only commenced with approval of revenues in 3RD regulatory Period starting from 2019. Revenue data do not contain revenues for elements that are not within network charges but are passed through by the DSO (e.g. concession fee, renewable energy support levy).Total allowed revenues have been reduced by the amount of upper grid charge to avoid double counting of costs (and inclusion of transmission costs in revenue figures). Data of connections points is not available. The value used is based on the number of measurement points in the grid of all DSO in Germany.

In terms of distribution revenues by connection points in 2013, Sweden presents the highest value (925€/connection point) followed by Luxembourg (576€/connection point), Estonia (489€/connection point), Finland (468€/connection point) and Netherlands (367€/connection point). The countries with the lowest allowed revenues per connection points are Lithuania (80€/connection point), Hungary (95€/connection point), Malta (101€/connection point) and Greece (105 €/connection point). Apart from the difference in cost items included in the allowed revenues in different Member States, it is interesting to notice the different relative position of countries in terms of average revenue by distributed energy and by connection point, which is due to the different composition of user typologies in different countries and their corresponding consumption levels.

6.3.4. Network charges

A comparison of electricity network charges across EU member states is a complex task for many reasons:

- limited availability of data for an average consumer class profile in different countries;
- in some countries the network cost include the transmission and other non-distribution activities;
- Some countries have a high number of DSOs with different tariff schemes that make the calculation of a homogeneous national tariff very complex.

In addition to the complexity associated with differences in tariff structures and comparability of data the definition of consumer groups (household, small Industrial and large Industrial) requires relevant simplifications as the characteristics and consumption patterns of users differ significantly across EU countries.

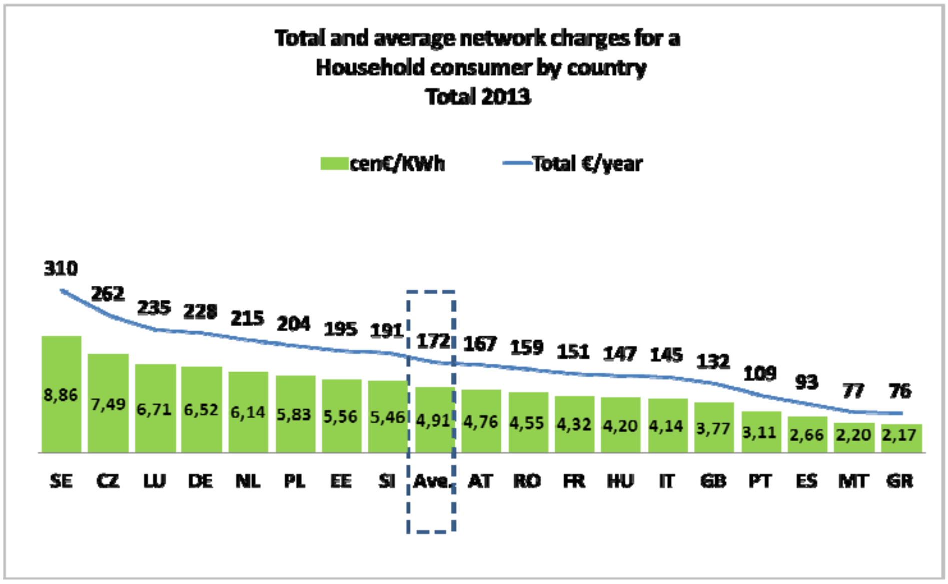
In this context, the indicators presented in the following section serve to show reference values and an overview of average network tariff for given consumer types across EU Member States, but does not mean to be representative of the specific context of each analysed country.

The calculation of the average network charges were mainly done by each of the national regulator using the definitions of consumer group provided by consultants. The characteristics of each consumers group (Annual consumption, contracted capacity and use hours) try to represent the average of users across EU Members States. However the consumption profile in some countries could be different to the consumers group defined.

Household consumer

The following figure shows the average distribution network tariff (cent€/KWh) for an electricity household consumer across EU countries. This data excludes transmission network cost, taxes and levies. The comparison is based on data provided by national regulators.

Figure 11: Total (€) and Average network charges (cent€/kWh) for Households, 2013



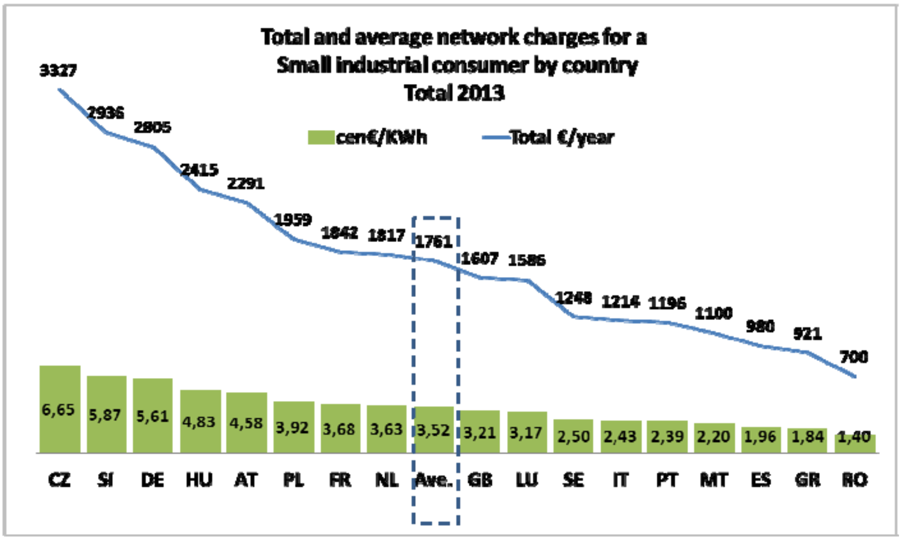
Household consumer with an annual consumption of 3500 kWh connected to the low voltage grid and a contracted capacity of 6 kW. Situation in 2013.
Source: Own calculation based on data provided by national regulators.
Detailed values of each tariff component by country are summarised in “Annex 5: Breakdown of electricity network annual charges by country – customer types”.
Spain: Average network tariff based on values for 2014.
Germany: The given average network cost include transmission revenues. Transmission costs are not charged separately but are part of distribution tariffs. The share of transmission costs within the distribution revenues can only very roughly be approximated and can vary greatly from DSO to DSO. On the low voltage level average share is very roughly about 5%-15%. Data on tariff structures were only available for DSOs in BNetzA responsibility. The given shares for fixed, capacity and energy charges are calculated of the average shares for the consumer groups from these BNetzA regulated DSOs. The average network cost in cent €/kWh is taken from the "Monitoringbericht 2014" and is calculated as an average of all DSO in Germany.

For household consumers, the average network charges in EU is approximately 4,91 cent € per Kwh (Based on data available of 18 countries). The countries with the highest average network charges are Sweden, Czech Republic, Luxembourg, Germany and The Netherlands. On the other hand, the countries with lower average tariffs are Greece, Malta, Spain, Portugal and Great Britain.

Small Industrial consumer

The following figure shows the average distribution network tariff (cent€/KWh) for a small industrial consumer across EU countries, excluding transmission network cost, taxes and levies. The comparison is based on data provided by national regulators.

Figure 12: Total (€) and Average network charges (cent€/kWh) for Small industrial consumer, 2013



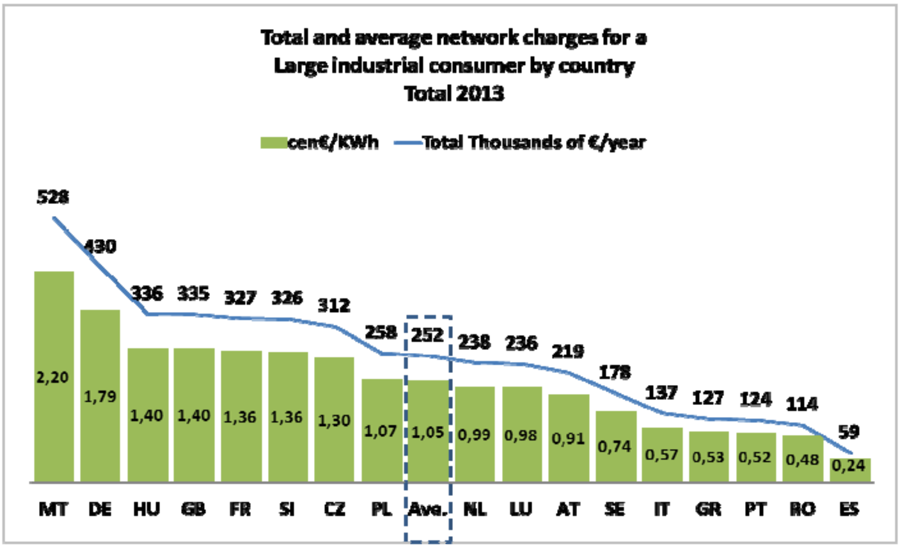
Small industrial consumer with an annual consumption of 50000 kWh connected to the low voltage grid and a contracted capacity of 35 kW. Situation in 2013
Source: Own calculation based on data provided by national regulators.
Detailed values of each component by country are summarised in "Annex 5: Breakdown of electricity network annual charges by country – customer types".
Spain: Average network tariff based on values for 2014.
Germany: Average network tariff includes transmission revenues. Transmission costs are not charged separately but are part of distribution tariffs. The share of transmission costs within the distribution revenues can only very roughly be approximated and can vary greatly from DSO to DSO. On the low voltage level average share is very roughly about 5%-15%. Average network costs for distribution only could not be calculated from these values. Data on tariff structures were only available for DSOs in BNetzA responsibility. The given shares for fixed, capacity and energy charges are calculated of the average shares for the consumer groups from these BNetzA regulated DSOs. The average network cost in cent €/kWh is taken from the "Monitoringbericht 2014" and is calculated as an average of all DSOs in Germany

For small industrial consumers, the average network charges in EU is approximately 3,52 cent € per Kwh (Based on data available of 17 countries) considering the charges of fixed, capacity and energy components. Czech Republic, Slovenia and Germany are the countries with higher average network charges. The countries with lower average network charges are Poland, Malta, Spain, Greece, and Romania.

Large Industrial consumer

The following figure shows the average distribution network tariff (cent€/KWh) for a large industrial consumer across EU Member States, excluding transmission network cost, taxes and levies. The comparison is based on data provided by national regulators.

Figure 13: Total (Thousands of €) and Average network charges (cent€/kWh) for Large industrial consumer, 2013



Large industrial with an annual consumption of 24000 MWh and 7000 use hours connected to the medium voltage grid and a contracted capacity of 4,000 kW. Situation in 2013.
Source: Own calculation based on data provided by national regulators.
Detailed values of each component by country are summarised in "Annex 5: Breakdown of electricity network annual charges by country – customer types".
Spain: Average network tariff based on values for 2014.
Germany: Average network tariffs include transmission revenues. Transmission costs are not charged separately but are part of distribution tariffs. The share of transmission costs within the distribution revenues can only very roughly be approximated and can vary greatly from DSO to DSO. On the medium voltage level average share is very roughly about 15-30%. Data on tariff structures were only available for DSOs in BNetzA responsibility. The given shares for fixed, capacity and energy charges are calculated of the average shares for the consumer groups from these BNetzA regulated DSOs. The average network cost in cent €/kWh is taken from the "Monitoringbericht 2014" and is calculated as an average of all DSOs in Germany.
On the medium voltage level average share is very roughly about 15-30%. Average network costs for distribution only could not be calculated from these value.
Data on tariff structures were only available for DSOs in BNetzA responsibility. The given shares for fixed, capacity and energy charges are calculated of the average shares for the consumer groups from these BNetzA regulated DSOs. The average network cost in cent €/kWh is taken from the "Monitoringbericht 2014" and is calculated as an average of all German DSOs.

For large industrial consumers, the average network charge in EU is approximately 1,05 cent € per Kwh (based on data available of 17 countries) considering the fixed, capacity and energy components. Malta, Germany and Hungary are the countries with higher average network charges. The countries with lower average network charges are Portugal, Spain and Romania.

6.4. Analysis of GAS Distribution Tariff

6.4.1. Tariff structure

In each EU country the tariff structure is defined by the national regulator or DSO according to certain customer segmentation. In many cases the segments are defined on a consumption basis, while in other countries tariffs are defined based on pressure level or other characteristics. The main variables that define gas tariff structure are described below:

- Annual consumption. Tariff levels are structured according to different intervals or bands of annual consumption. In some countries the consumption is expressed in cubic meters of gas (m3 /year), however in others countries the energy consumption by year is used (kWh/year).
- Pressure level. Pressure level that customers are connected to. Usually there are two levels: low pressure and medium/high pressure (usually pressure level higher than 4-6 bar).
- Used capacity, corresponding to the maximum metered daily consumption for a 12 month time window
- Metered or not metered capacity (Daily, Non-Daily,…) Tariff levels are designed according to the capabilities of metering devices to obtain data (Peak daily demand, time of use consumption, etc.)
- Geographic zone. In some countries the geographic zone is one of the variables used to define tariff levels.

In most countries (18) distribution tariffs are defined according to annual **consumption bands.** The connection points/consumers are segmented into consumption bands or tariff level by their demand behaviour. For the low consumption bands, the energy price is higher than those in upper levels.

These countries use **annual consumption** as a variable to define their tariff structure: Austria, Croatia, Czech Republic, Denmark, Estonia, France, Germany, Ireland, Italy, Lithuania, Luxembourg, The Netherlands, Poland, Portugal, Slovakia, Slovenia, Spain and Great Britain.

However in the Czech Republic, Denmark, Luxembourg, Spain and Portugal, the tariff structure is defined by an **annual consumption band** for each **pressure level.** So in these countries there are some tariffs for low pressure and different consumption bands and other tariffs for medium pressure and other consumption bands.

In Austria utilization charges are segmented by network **pressure level**, **measurement, consumption level** and **geographic zone**. Since there are 2 network levels, 2 measurement types (for level 3 only: with or without hourly peak measure), 9 geographical zones (the 9 Austrian Provinces or Länder) and 10 consumption blocks, there are more than 300 values.

In Germany and The Netherlands the distribution tariff is set according to **annual consumption band** and **used capacity.** In Poland, tariff blocks are defined by pressure level, **used capacity** and **annual consumption.** There is moreover one category for clients with an hourly capacity withdrawal not exceeding 110 kWh/h, subdivided into four groups of customers based on yearly consumption, and another category for clients with an hourly capacity withdrawal exceeding 110 kWh/h – subdivided into six groups, based on the level of booked capacity.

In others, like Hungary, tariff blocks are defined by the **size of gas meters** and not by consumption (Below 20m3/h, 20-100 m3/h, 100-500 m3/h and Above 500 m3/h).

The following table describes the variables involved in the definition of the tariff levels for each country.

Table 26: Key variables used in the definition of gas distribution tariffs structure in EU countries. (2013)

Country	Pressure Level	Annual Consumption	Used Capacity	Meter capabilities
Austria	X	X		X
Belgium	N.A	N.A	N.A	N.A
Bulgaria	N.A	N.A	N.A	N.A
Croatia		X		
Czech Republic	X	X		
Denmark		X		
Estonia		Depend on DSO. Only one DSO the tariff levels are define by annual consumption. Others DSO´s have only one tariff level (€/m3)		
Finland	Depends on DSO	Depends on DSO	Depends on DSO	Depends on DSO
France		X		
Germany		X	X	
Greece	No specific methodology	No specific methodology	No specific methodology	No specific methodology
Hungary			X	
Ireland		X		
Italy		X		
Latvia	N.A	N.A	N.A	N.A
Lithuania		X		
Luxembourg	X	X		
Netherlands		X	X	
Poland		X	X	
Portugal	X	X		
Romania	N.A	N.A	N.A	N.A
Slovakia		X		
Slovenia		X		
Spain	X	X		
Sweden	Depends on DSO	Depends on DSO	Depends on DSO	Depends on DSO
Great Britain		X		
Total countries	5	18	4	1

Source: elaboration based on data provided by national regulators. Situation in 2013

6.4.2. Tariff components

The analysis involves the identification of the gas distribution tariff components and comparison of the weight of each component in EU member states for two different consumer groups: household and industrial consumer groups [(1).]

- Household consumer of natural gas with a standard annual consumption of 15 MWh

- Industrial consumer of natural gas with a standard annual consumption of 50 GWh and 7000 use hours

Gas networks tariffs usually have the following components:

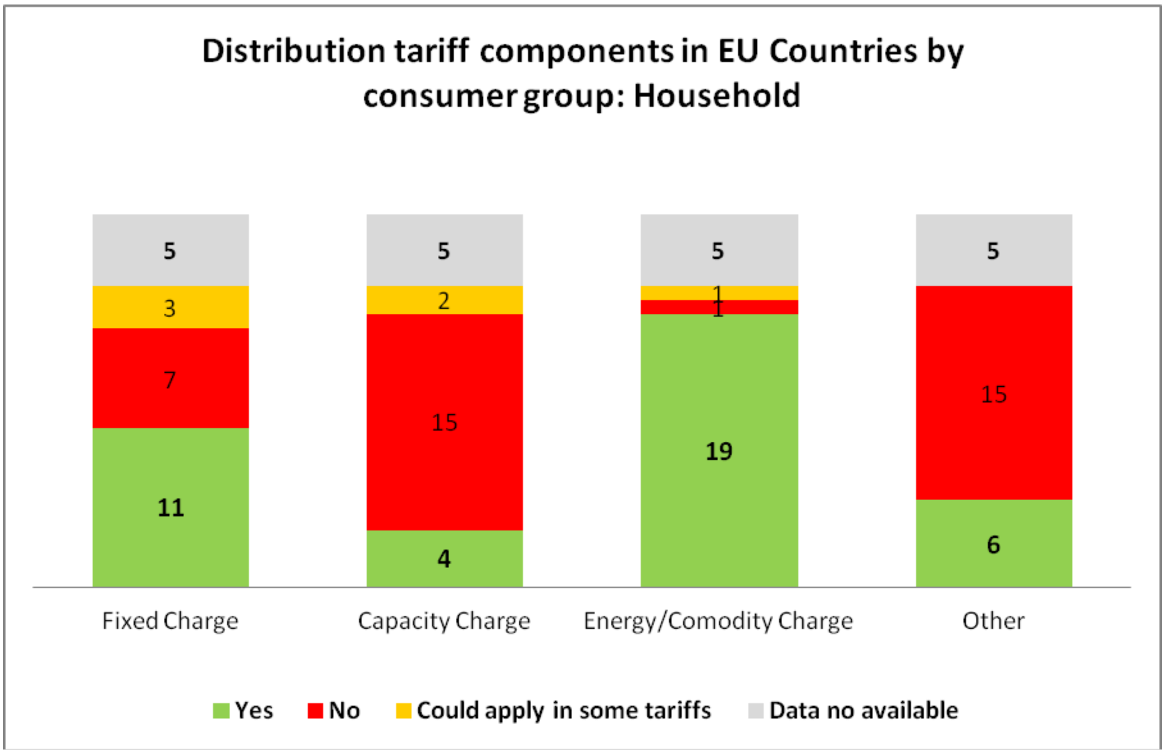
- Fixed charge: In some countries it is known as standing charge or service charge by connection point/consumer (€/day, €/month, €/year).
- Capacity charge: charges for the availability of network capacity would normally be expressed in terms of a maximum daily rate reserved by the consumer either in volumetric or energy terms (Max Kw/h/ day, m3/h/day). In most countries, the user faces considerable charges, when the maximum capacity usage is exceeded.
- Energy charge: it is the variable or volumetric component of the tariff. In some countries it is known as commodity charge (€/Kwh, €/m^3).

6.4.2.1. Household consumers

Identification of tariff components

The gas distribution tariff components applied in EU countries for household consumers are summarized in the figure below.

Figure 14 Distribution Tariff GAS components in Households (Number of countries)



Source: Own elaboration based on data provided by national regulators. Situation in 2013. Data from Belgium, Bulgaria, Greece, Latvia and Romania is not available from this consumer group.
Details for each country are summarised in "Annex 3: Summary of gas distribution tariff components by consumer group".

Next table provides details on the tariff components applied to household consumer across EU Member States.

Table 27: Distribution tariff components identified by country for a Household consumer

Country	Fixed Charge	Capacity charge	Energy charge	Other
Austria	Yes, depending of annual consume	Yes, depending of annual consume	Yes	No
Belgium	N.A	N.A	N.A	N.A
Bulgaria	N.A	N.A	N.A	N.A
Croatia	Yes	No	Yes	No
Czech Republic	Yes	No	Yes	No
Denmark	No	No	Yes	No
Estonia	No	No	Yes	No
Finland	Yes, varies depending on DSO	No	Yes, varies depending on DSO	No
France	Yes	No	Yes	No
Germany	Yes, if the annual consumption of up to 1.5m kWh[1] and a maximum exit load of 500 kWh/h	Yes, if Annual consumption above 1.5m kWh/a	Yes	Yes, Metering
Greece	N.A	N.A	N.A	N.A
Hungary	Yes	No	Yes	Yes, Metering
Ireland	No	Yes	Yes	No
Italy	Yes	No	Yes	No
Latvia	N.A	N.A	N.A	N.A
Lithuania	No	No	Yes	No
Luxembourg	No	No	Yes	Yes, Metering
Poland	No	Yes	Yes	No
Portugal	Yes	No	Yes	No
Romania	N.A	N.A	N.A	N.A
Slovakia	Yes	No	Yes	No
Slovenia	Yes	No	Yes	Yes. Metering
Spain	Yes	No	Yes	No
Sweden	Yes	No	Yes	No
The Netherlands	Yes	Yes	No	Yes, Metering
Great Britain	No	Yes	Yes	Yes, Metering

Source: Own elaboration on data provided by national regulators.
N.A: Data not available

For household consumers, 11 out of 21 countries with available data have a fixed charge as part of the tariff. This fixed component is a per customer component (€/month or year), while capacity related charges are much less common. Countries with a fixed component are: Croatia, Czech Republic, France, Hungary, Italy, Portugal, Slovakia, Slovenia, Spain, Sweden and The Netherlands. In Austria and Germany a fixed component could apply if the annual energy consumption is lower than a set limit. If the customer exceeds this amount, he is charged with a capacity component and not with a fixed component.

There are 4 countries with a capacity component related charge. Usually when a fixed charge component is present no capacity charge component is applied. An exceptional case is The Netherlands where, according to the yearly energy consumption, the tariff could have both components. Moreover, there are 2 countries with just a capacity component: Ireland and Poland

In Great Britain, supply points with annual consumption less than 73200 KWh are charged by a capacity charge (typical household consumers). Supply points with an annual consumption between 73200 KWh and 732000 KWH are charged with a fixed component that depends on the frequency of meter reading, plus a capacity charge.

In Austria and Germany a capacity component charge could apply as it is commented above.

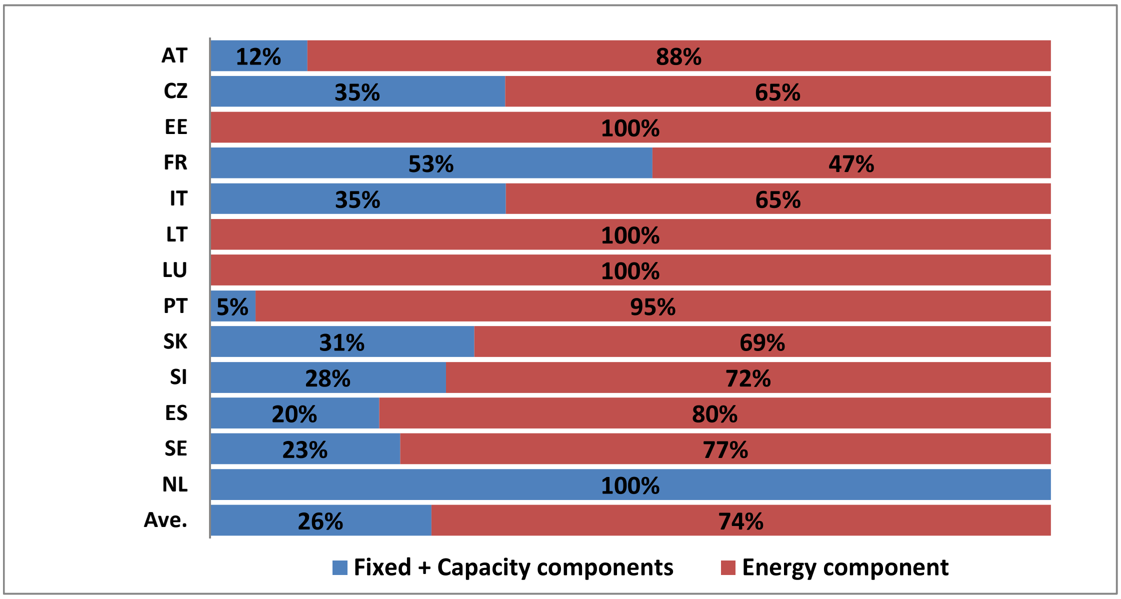
All but one of the EU member states with available information (19) have an energy related component as part of the distribution tariff structure. The Netherlands is the exception, as household customers in that country only pay a capacity charge and a fixed annual charge (i.e. they do not pay an energy related component as part of the distribution tariff structure). Usually there are different intervals for annual consumption levels (kWh or m3), being the unit prices of the lowest consumption levels more expensive than the unit prices for the highest levels of consumption. In Denmark, Estonia Lithuania and Luxembourg all consumers are charged only an energy related (per m3) distribution tariff.

In the majority of countries (15) there are no "other" distribution tariff components in the household category. However, there are 6 cases with some other type of components. In Germany, Hungary, Luxembourg, Slovenia, The Netherlands and Great Britain, there is a tariff component that charges the use of metering devices and this charge is regulated by Law.

Weight of tariff components

The following figure shows a comparison of the weight of tariff components across EU member states for household consumers taking into account: fixed charges, capacity charges and energy charges.

Figure 15: Distribution Tariff Gas component weight for Households



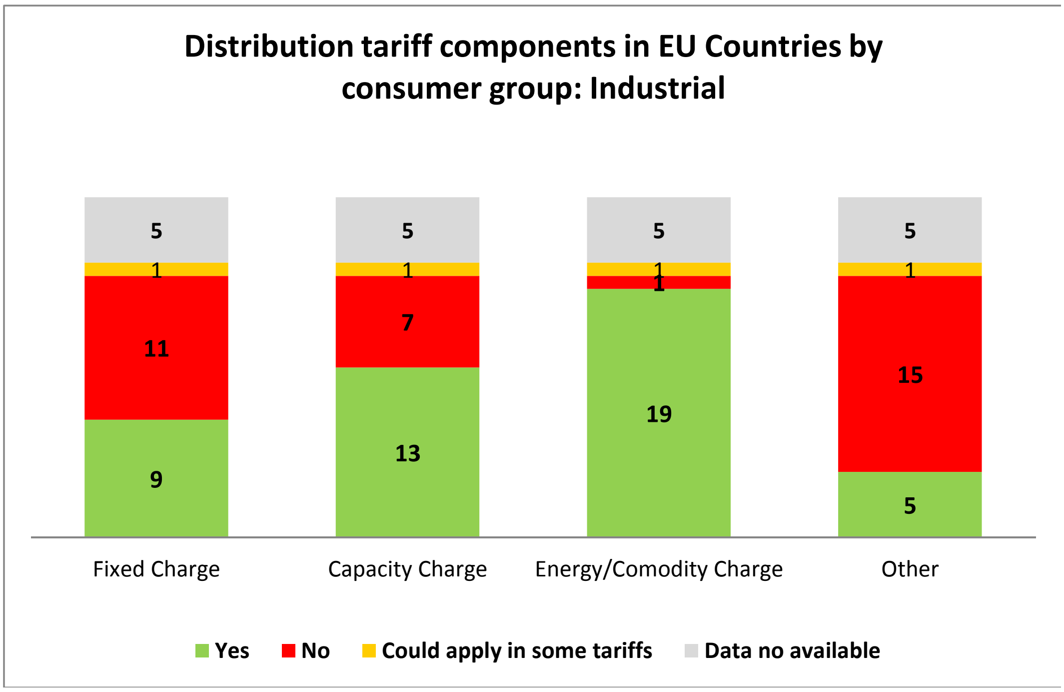
Household consumer with an annual consumption of 15000 KWh. Situation in 2013
Source: Own calculation based on data provided by national regulators regarding Fixed charges, Capacity charges and Energy charges,
Detailed values of each component by country is summarised in "Annex 6: Breakdown of gas network annual charges by country – customer types"

The figure above shows the weight of each tariff component for a household client in countries with available data. In 11 of 13 countries, the energy component has more weight than fixed or capacity components. Only in France and the Netherlands, fixed or capacity component has more weight than the commodity charge. In The Netherlands there is not an energy component for this type of consumers.

6.4.2.2. Industrial consumers

The gas distribution tariff components applied in the EU countries for the Industrial category are summarized in the figure below.

Figure 16: Distribution Tariff Gas components for Industrial Consumers (Number of countries)



Source: Own elaboration based on data provided by national regulators. Situation in 2013. Data from Belgium, Bulgaria, Greece, Latvia and Romania is not available from this consumer group.

Details of each country are summarised in "Annex 3: Summary of gas distribution tariff components by consumer group".

Next table details the tariff components defined for an industrial consumer across EU Member States.

Table 28: Distribution tariff components identified by country for Industrial consumer

Country	Fixed Charge	Capacity charge	Energy charge	Other
Austria	No	Yes	Yes	No
Belgium	N.A	N.A	N.A	N.A
Bulgaria	N.A	N.A	N.A	N.A
Croatia	Yes	No	Yes	No
Czech Republic	Yes	No	Yes	No
Denmark	No	No	Yes	No
Estonia	No	No	Yes	No
Finland	Yes, varies depending on DSO	Yes, varies depending on DSO	Yes, varies depending on DSO	Yes, varies depending on DSO
France	Yes	Yes	Yes	No
Germany	No	Yes	Yes	Yes, Metering
Greece	N.A			
Hungary	No	Yes	Yes	Yes, Metering
Ireland	No	Yes	Yes	No
Italy	Yes	No	Yes	No

Country	Fixed Charge	Capacity charge	Energy charge	Other
Latvia	N.A	N.A	N.A	N.A
Lithuania	No	No	Yes	No
Luxembourg	No	Yes	Yes	Yes, Metering
Poland	No	Yes	Yes	No
Portugal	Yes	Yes	Yes	No
Romania	N.A	N.A	N.A	N.A
Slovakia	Yes	Yes	Yes	No
Slovenia	Yes	Yes	Yes	Yes. Metering
Spain	No	Yes	Yes	No
Sweden	Yes	No	Yes	No
The Netherlands	Yes	Yes	No	No
Great Britain	No	Yes	Yes	Yes, Metering

Source: Own elaboration based on data provided by national regulators. N.A: Data not available.

For industrial clients a capacity charge (13) applies in most countries rather than a fixed charge (9), contrary to what is applied in the case of household clients.

Capacity components are applied in Austria, France, Germany, Hungary, Ireland, Luxembourg, Poland, Portugal, Slovakia, Slovenia, Spain, The Netherlands and Great Britain. A fixed component applies in Croatia, Czech Republic, Italy and Sweden. In France, Portugal, Slovakia, Slovenia and The Netherlands both components could apply for industrial consumers.

In Austria, fixed and capacity charges are differentiated by province and not by consumption block. Also a discount of the capacity charge applies to industries consuming between March and October only.

The energy component exhibits a similar situation to the case of household customers. In almost all countries the variable cost of distribution network is charged as an energy component (19), been the Netherlands the exception. There is only one country identified with time of use differentiation: Portugal. In Portugal for medium pressure and low pressure with an annual consumption higher than 10000 m3 the energy term is differentiated in peak and off peak time zone.

In terms of “other” components in industrial consumers, the situation is similar to that in household consumers.

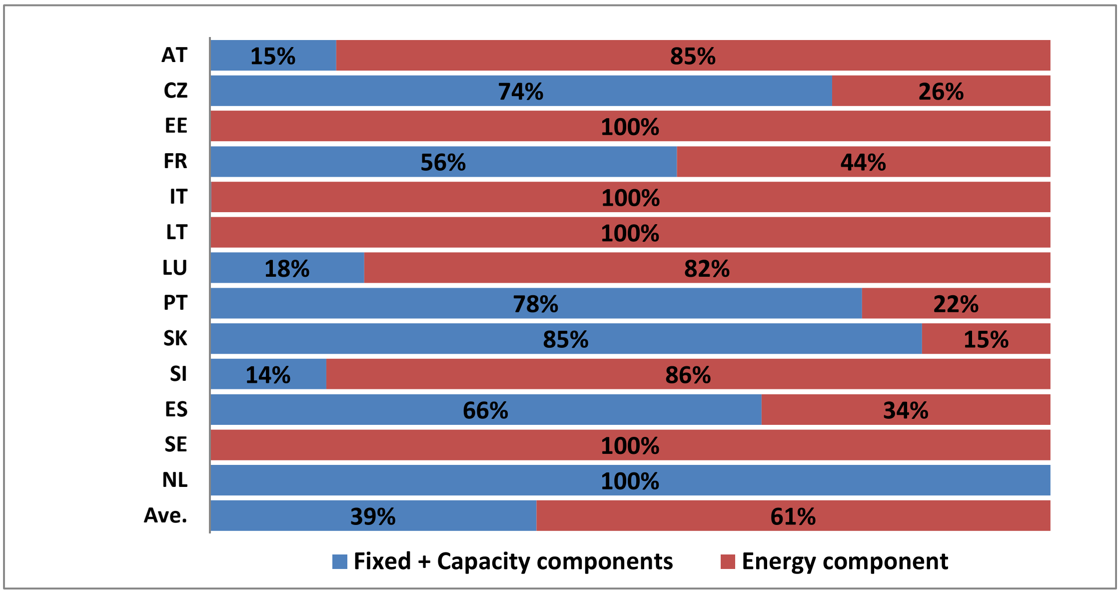
In Finland and Sweden there is no single approach used by DSOs to allocate distribution costs to the tariffs. DSOs have freedom to use the tariff components that they prefer. DSOs are in charge of setting the distribution tariffs as well.

Greek Distribution tariffs are bundled together with retail tariffs, so it is impossible to isolate and examine the tariffs for distribution activities.

Weight of tariff components

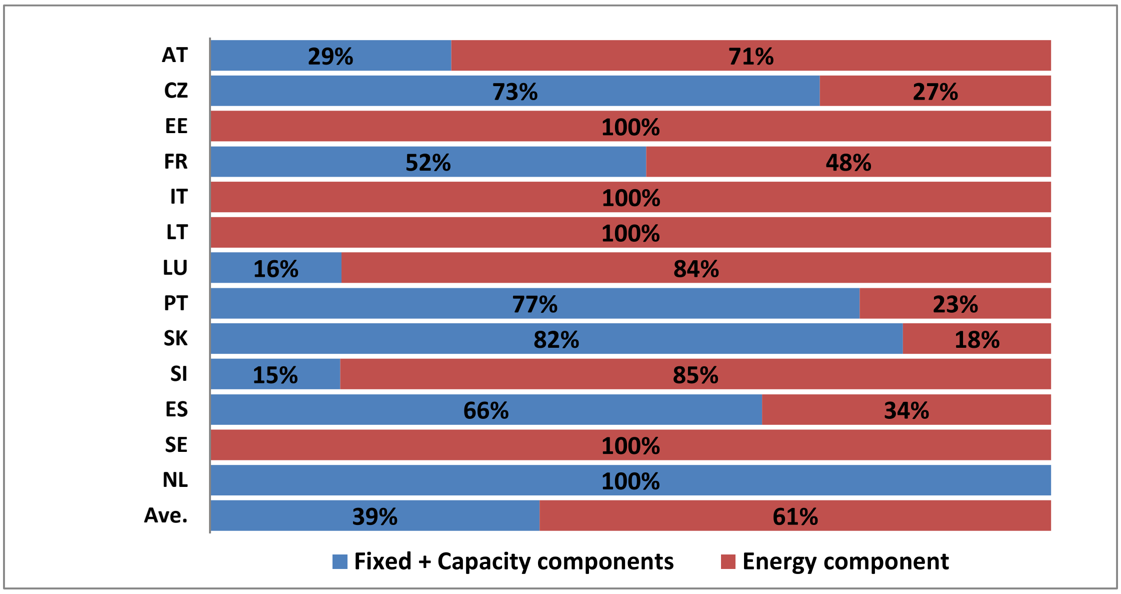
The following figures show a comparison of the weight of different tariff components across EU member states for two types of Industrial consumers. For the calculation, the following components were considered: fixed charge, capacity charge and energy charge.

Figure 17: Distribution Gas Tariff component weight for an Industrial consumer with an annual consumption of 50GWh



Industrial consumer with an annual consumption of 50,000 MWh and 7,000 use hours.
Source: Own elaboration based on data provided by national regulators for Fixed charges, Capacity charges and Energy charges.
Detailed values of each component by country are summarised in “Annex 6: Breakdown of gas network annual charges by country – customer types”

Figure 18: Distribution Gas Tariff component weight for an Industrial consumer with an annual consumption of 90GWh



Industrial consumer with an annual consumption of 90000 MWh and 7000 use hours.
Source: Own elaboration based on data provided by national regulators for Fixed charges, Capacity charges and Energy charges.
Detailed values for each component by country are summarised in "Annex 6: Breakdown of gas network annual charges by country – customer types"

For both industrial consumer profiles (50GWh and 90GWh annual consumption), the capacity or fixed component has an average weight of approximately 39% across EU Member States (13 countries with available data), while the energy or commodity component represents around 61% of the distribution network tariff.

Countries where the energy component has a higher weight than the sum of fixed and capacity components are: Austria, Estonia, Italia, Lithuania, Luxembourg, Slovenia and Sweden. In Estonia and Lithuania network costs are recovered only through an energy component.

In some countries such as Czech Republic, Portugal, Slovakia and Spain the weight of fixed and capacity components are at least 70% of network tariff charges. In the Netherlands, network costs are recovered through capacity and fixed components. In the Netherlands, there is not an energy component for the industrial consumer either the household consumer.

6.4.3. Allowed revenues for gas distribution activities

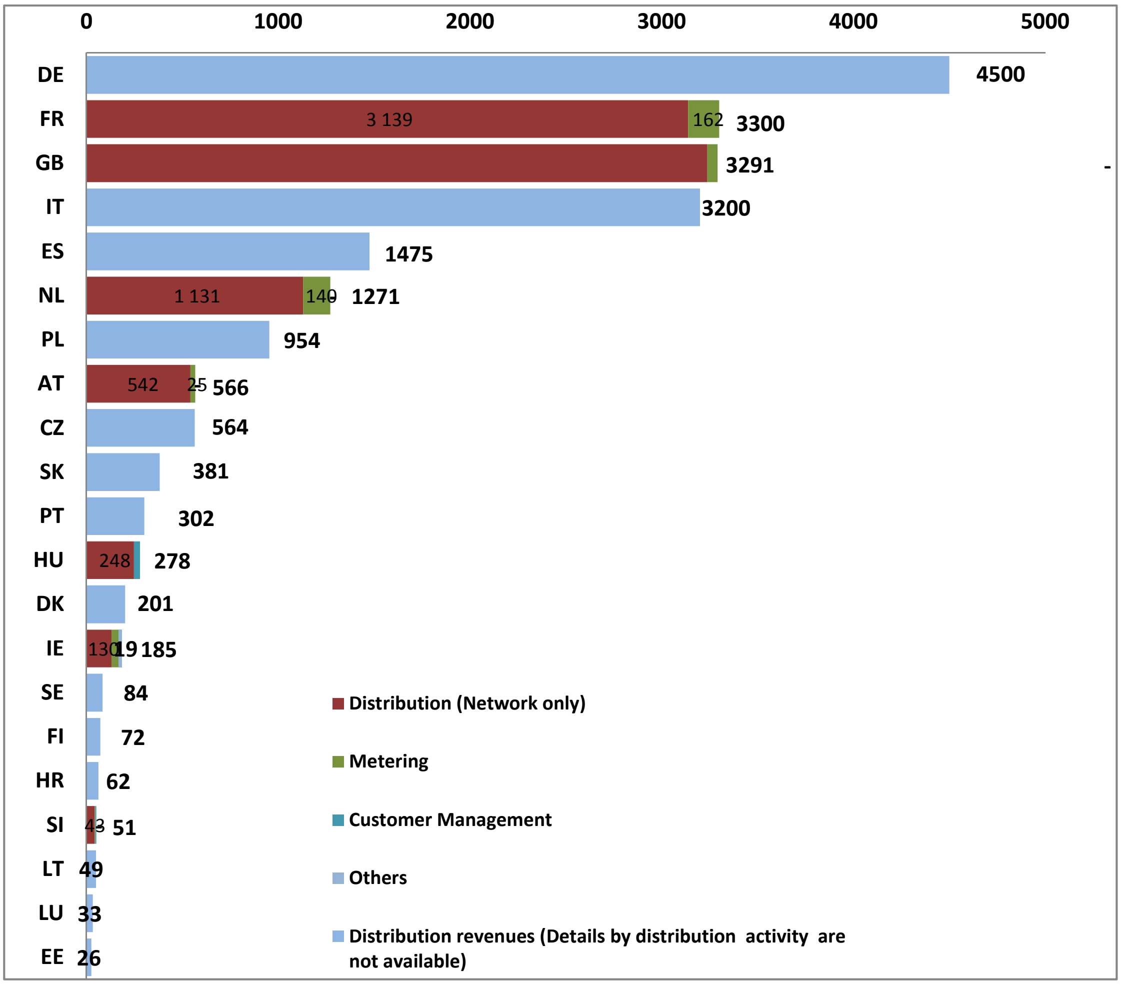
The objective of this section is to provide an overview of the allowed revenues for gas distribution activities across EU member states. The analysis is based on the data facilitated by national regulators.

As in the electricity sector, the comparison of ratios of allowed distribution revenues is a complex task, because in each country DSO do not provide an identical and homogenous service delivered in comparable conditions (Density of population connected; geographical constraints with an impact on network design and operations).

Given the above, the indicators presented in this section are meant to be a starting point for an overview of distribution revenues across EU Member States, and are not meant to identify differences in efficiency or possible best practices.

The following figure shows the total gas distributions revenues across EU Member states in 2013. The revenues include: distribution network usage, metering, customer management and other revenues related with distribution activities. Transmission/transport cost, taxes and levies are excluded.

Figure 19: Gas Distribution revenues across EU Member States in 2013. (Millions of Euros)



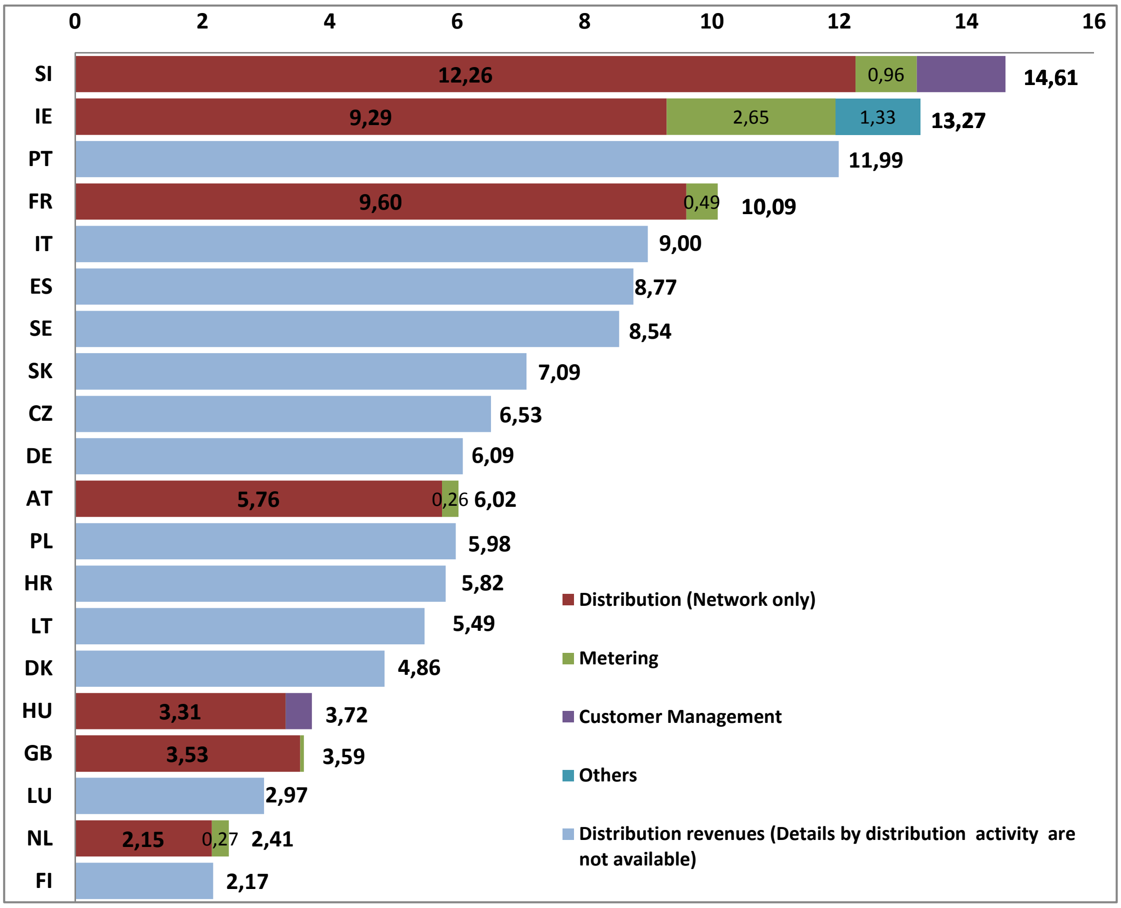
Source: Own elaboration on data provided by National Regulators.

Details and comments on the values for each country are summarised in Annex 8. Allowed gas distribution revenues across EU Member states in 2013.
Germany: Distribution Allowed revenues of DSOs under responsibility of BNetzA . Allowed revenues of other DSO under Federal States responsibilities are unknown.

In absolutes terms, the country with the highest allowed revenues for distributions activities is Germany (4500 million €) followed by France (3500 million €), Great Britain (3291 million €), Italy (3200 million €), and Spain (1475 million €). The countries with the lowest allowed revenues in absolute terms are Estonia, Luxembourg and Lithuania.

The following figure shows gas distributions revenues (excluding transmission cost, taxes and levies) per energy delivered (€/ MWh) across EU Member states in 2013.

Figure 20: Gas Distribution revenues per energy delivered across EU Member States in 2013. (Euros per MWh)

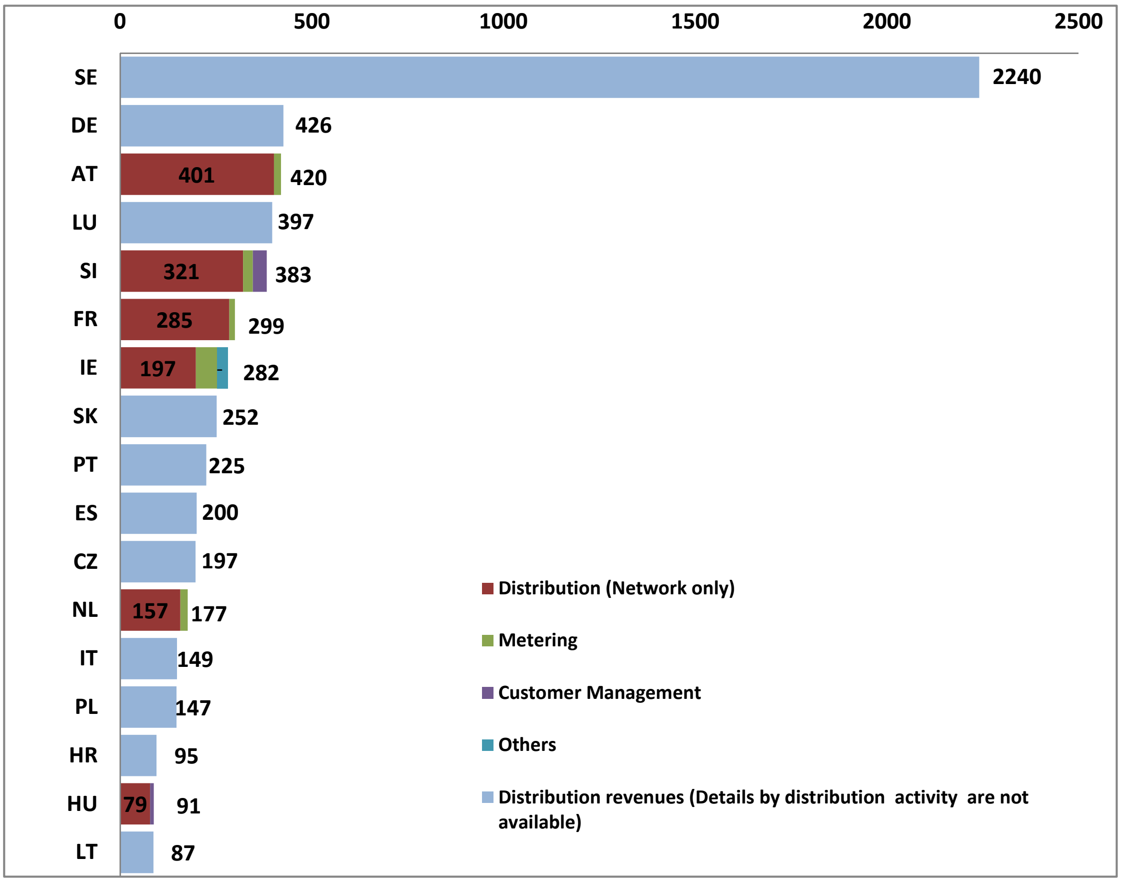


Source: Own elaboration on data provided by National Regulators.
Details and comments on the values for each country are summarised in Annex 8. Allowed gas distribution revenues across EU Member states in 2013.
Germany: Distribution Allowed revenues of DSOs under responsibility of BNetzA. Allowed revenues of other DSO under Federal States responsibilities are unknown.

According to the information available, the country with more allowed revenues per MWh distributed is Slovenia (14,61 €/MWh), followed by Ireland (13,27 €/MWh), Portugal (11,99 €/MWh) and France (10,09 €/MWh). On the other hand the countries with the lowest allowed revenues per energy are Hungary, Great Britain, Luxembourg, The Netherlands and Finland.

The following figure shows gas distributions revenues (Excluding transmission cost, taxes and levies) per connection point (€/connection point) across EU Member states in 2013.

Figure 21: Gas Distribution revenues per connection point across EU Member States in 2013. (Euros per connection point)



Source: Own elaboration on data provided by National Regulators.
Details and comments on the values for each country are summarised in Annex 8. Allowed gas distribution revenues across EU Member states in 2013.
Germany: Distribution Allowed revenues of DSOs within the BNetzA. Allowed revenues of other DSO under Federal States responsibilities are unknown.

In terms of distribution revenues by connection points in 2013, Sweden is the country with the highest revenue per connection point (2240 €/connection point), followed by Germany (426 €/connection point), Austria (420€/connection point), Luxembourg (397 €/connection point), Slovenia (383€/ connection point) and France (299€/connection point). The countries with the lowest allowed revenues per connection points are Lithuania (87€/connection point), Hungary (88€ /connection point) and Croatia (95 € /connection point).

6.4.4. Network charges

In this section we analyse the average gas network tariff for different consumer groups. The analysis is based on data provided by national regulators for a given consumer profile. The consumer groups are defined as follows:

- Household consumer of natural gas with a standard annual consumption of 15 MWh.
- Industrial consumer of natural gas with a standard annual consumption of 50 GWh and 7000 use hours
- Industrial consumer of natural gas with a standard annual consumption of 90 GWh and 7000 use hours

In addition to the complexity associated with differences in tariff structures and comparability of data, the definition of consumer groups (household, small Industrial and large Industrial) requires relevant simplifications as the characteristics and consumption patterns of users can differ significantly across EU countries.

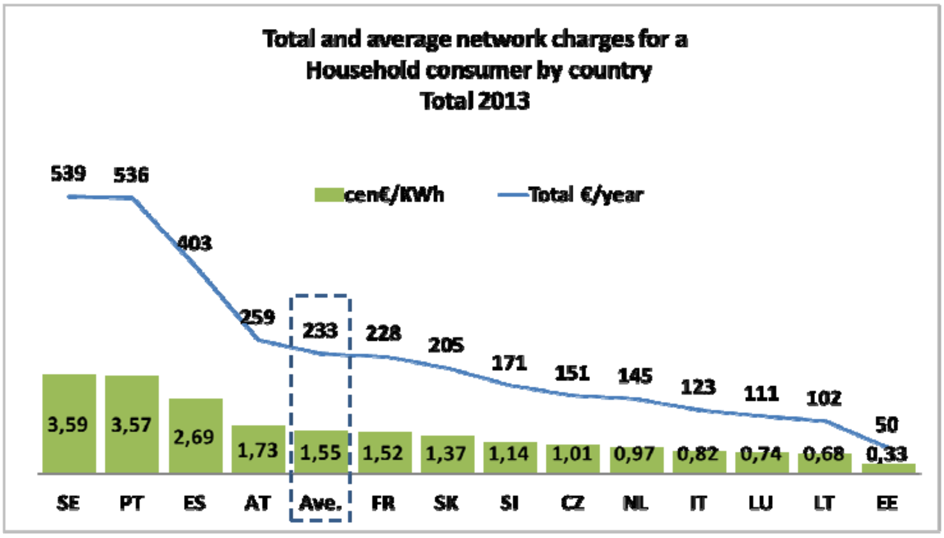
In this context, the indicators presented in the following section are meant to show reference values that can be compared across different countries for given consumer types, but do not mean to be representative of the specific context and typical consumer profile of each analysed country.

As in the electricity sector, the average network charges calculation were mainly done by each of the national regulator using the definitions/guides of consumer group provided by the consultants. The characteristics of each consumers group (annual consumption and use hours) try to represent the average of users across EU Members States. However the consumption profile in some countries could be different to the consumers group defined.

Household consumer

The following figure shows the average distribution network tariff (cent € per energy) for a household consumer across EU countries. The values are net of taxes and levies. The comparison is based on data provided by national regulators.

Figure 22: Total (€) and Average network charges (cent€/kWh) for Households, 2013



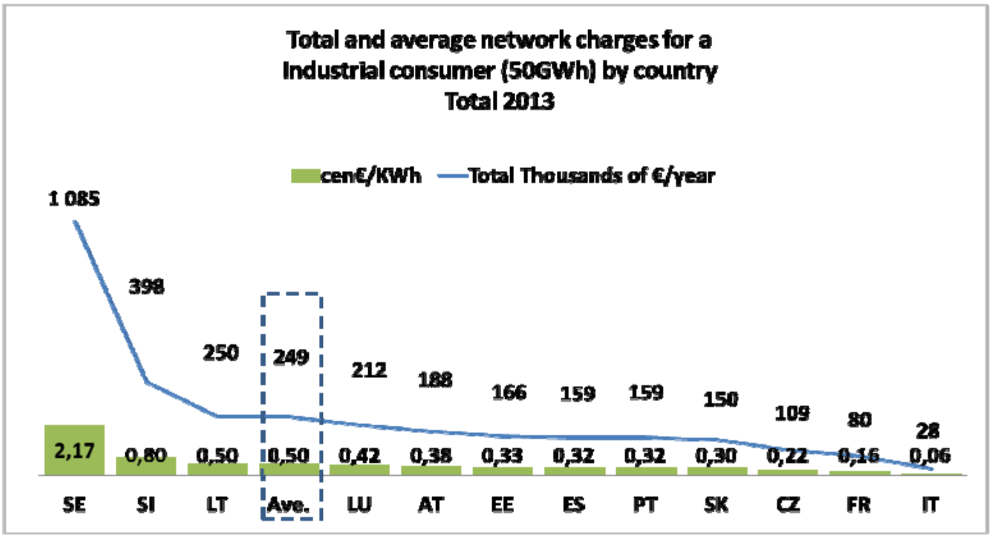
Household consumer with an annual consumption of 15,000 kWh. Situation in 2013.
Source: Own elaboration based on data provided by national regulators. Detailed values for each component by country are summarised in "Annex 6: Breakdown of gas network annual charges by country – customer types".
Spain: average network tariff includes transmission cost.

According to the available data, Sweden, Portugal and Spain are the countries with highest average tariffs for a household client (15000 KWh of annual consumption). In Sweden the energy component (417€, 0,0278 €/KWh) has more weight than the fixed component (122€/year), as well as in Portugal (Energy component: 507€, 0,0337 €/KWh; fixed component: 29€/year). On the other hand the countries with the lowest network tariff are Estonia, Lithuania and Luxembourg.

Industrial consumer

The following figures show the average distribution network tariff (cent € per energy) for two types of industrial consumers (50 GWh and 90 GWh of annual consumption) across EU countries. The figures in the graph are net of taxes and levies.

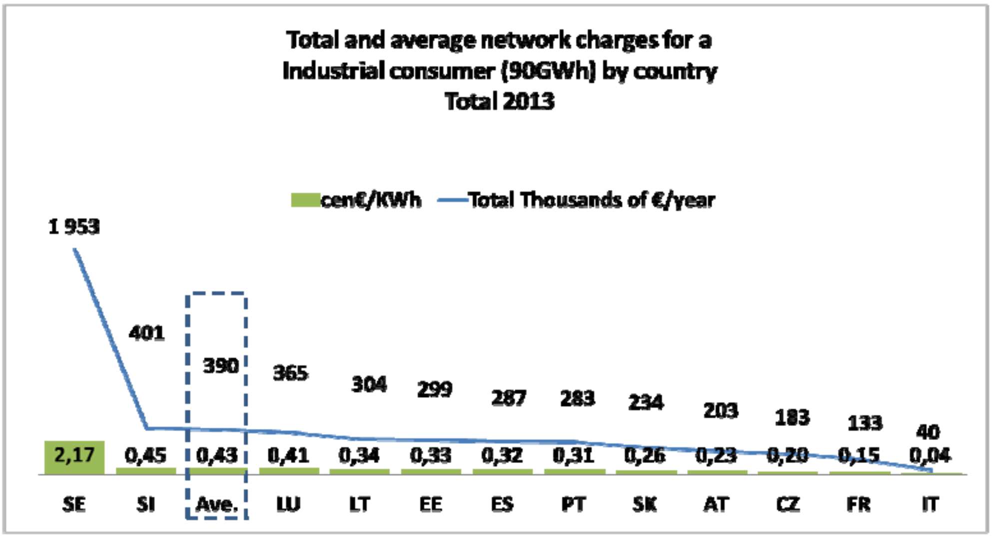
Figure 23: Total (€) and Average network charges (cent€/kWh) for Industrial consumer (50GWh), 2013



Industrial consumer with an annual consumption of 50000000 kWh and 7000 use hours. Situation in 2013.
Source: Own elaboration based on data provided by national regulators.
Detailed values for each component by country are summarised in "Annex 6: Breakdown of gas network annual charges by country – customer types".
Spain: average network tariff includes transmission cost.

For an industrial consumer with an annual consumption of 50 GWh, Sweden, Slovenia and Lithuania are the countries with higher average net gas network tariffs. On the other hand Italy, France and The Czech Republic are the countries with the lowest tariffs.

Figure 24: Total (€) and Average network charges (cent€/kWh) for Industrial consumer (90GWh), 2013



Industrial consumer with an annual consumption of 90000000 kWh and 7000 use hours. Situation in 2013.
Source: Own elaboration based on data provided by national regulators.

Detailed values for each component by country are summarised in “Annex 6: Breakdown of gas network annual charges by country – customer types”.
Spain: average network tariff includes transmission cost.

For an industrial consumer with an annual consumption of 90 GWh, Sweden, Slovenia, Luxembourg and Lithuania are the countries with more expensive distribution average net network tariffs. On the other hand Italy, France and The Czech Republic are the countries with the lowest tariffs.

1. Annex

Annex 1: Responsible in setting distribution tariffs by country

Country	DSO	Government	The NRA	Main Responsibility
Austria	Providing opinions	Providing opinions	Sets principles, methodology, values, approves tariffs	NRA
Belgium	Main responsibility	Defines main principles	Approves DSO proposals	NRA/DSO
Bulgaria				Not available
Croatia			Sets tariff structure after public consultation	NRA
Cyprus	Prepare a tariff proposal and submit it to the NRA for their approval		Prepares the tariff methodology (issued as a regulation)	NRA/DSO
Czech Republic			Main responsibility	NRA
Denmark	Main responsibility	Sets rules	Set rules and approved tariff. Monitors ex-post	NRA/DSO
Estonia	Main responsibility	Defines main principles	Sets rules and monitors ex-post	NRA/DSO
Finland	Sets the tariff levels			NRA/DSO
France		Defines main principles	Main responsibility	NRA
Germany	Implements	Issues tariff structure rules	Main responsibility	NRA
Greece			Electricity. Sets the structure (following consultation) Gas. The tariff is defined by the Max Allowed revenues	NRA
Hungary		Defines main principles	Main responsibility	NRA
Ireland	Calculates for NRA approval		Main responsibility	NRA
Italy	Provides the regulator with data on its cost and quality levels	Defines main principles	Issues the tariff structure	NRA
Latvia				Not available
Lithuania	Proposes after consultation	Defines main principles	Sets principles, methodology, values, approves tariffs	NRA
Luxembourg			Main responsibility	NRA
Malta	Proposes the tariff structure	Consulted by Regulator	Approves	NRA/DSO
Poland	Proposes tariff structure to NRA	Sets general rules	Takes decision on tariff structure based on DSO proposal	NRA/DSO
Portugal		Define main principles	Main responsibility	NRA
Romania	May propose a change in the tariff and the NRA should asses the request. All DSO apply the same tariff structure.		Main responsibility.	NRA
Slovakia	Calculates for NRA approval	Defines main principles	Sets principles, methodology, values, approves tariffs	NRA/DSO
Slovenia		Issues primary law	Sets a general act with	NRA

Country	DSO	Government	The NRA	Main Responsibility
			methodologies, and charges	
Spain			Sets the tariff structure (1)	NRA
Sweden	Decides on the tariff structure		May take decisions on tariff structures in individual cases, according to non-discriminating requirements	NRA/DSO
The Netherlands	Proposes tariffs (and allocations of total income) to the NRA	Sets the principal of the tariff structure	Makes final decision on proposed tariffs	NRA/DSO
Great Britain	Proposes tariff structure to NRA		Takes decision on tariff structure based on DSO proposal	NRA/DSO

(1) A draft amendment to the Electricity Act, which is still under parliamentary procedure, provides that the definition of the tariff structure will be assumed by the Ministry of Industry, Energy and Tourism.

Annex 2: Summary of electricity distribution tariff components by consumer group

Country	Consumer group	Fixed Charge	Capacity charge	Energy charge	Energy reactive	Other
Austria	Household	Yes	No	Yes	No	No
	Small industrial	No	Yes	Yes	No	No
	Large industrial	No	Yes	Yes	No	No
Belgium	Household	Yes	No	Yes	No	No
	Small industrial	N.A	N.A	N.A	N.A	N.A
	Large industrial	Yes	Yes	Yes	Yes	No
Bulgaria	Household	N.A	N.A	N.A	N.A	N.A
	Small industrial	N.A	N.A	N.A	N.A	N.A
	Large industrial	N.A	N.A	N.A	N.A	N.A
Croatia	Household	No	No	Yes	No	Yes, Metering
	Small industrial	No	Yes	Yes	Yes	Yes, Metering
	Large industrial	No	Yes	Yes	Yes	Yes, Metering
Cyprus	Household	Yes	No	Yes	No	No
	Small industrial	Yes	No	Yes	No	No
	Large industrial	Yes	No	Yes	No	No
Czech Republic	Household	Yes	No	Yes	No	No
	Small industrial	No	Yes	Yes	Yes	No
	Large industrial	No	Yes	Yes	Yes	No
Denmark	Household	Yes	No	Yes	No	No
	Small industrial	Yes	No	Yes	No	No
	Large industrial	Yes	No	Yes	No	No
Estonia	Household	No	Yes, it s posible. There are two options: Capacity + Energy or Energy	Yes	No	No
	Small industrial	No	Yes, its posible. There	Yes	Yes	N.A

Country	Consumer group	Fixed Charge	Capacity charge	Energy charge	Energy reactive	Other
			are two options: Capacity + Energy or Energy			
	Large industrial	No	Yes	Yes	Yes	No
Finland	Household	No	Yes	Yes	No	No
	Small industrial	No	Yes	Yes	No	No
	Large industrial	No	Yes	Yes	Yes	No
France	Household	Yes	Yes	Yes	No	No
	Small industrial	Yes	Yes	Yes	Yes	No
	Large industrial	Yes	Yes	Yes	Yes	No
Germany	Household	Yes	No	Yes	No	No
	Small industrial	No	Yes	Yes	Yes	No
	Large industrial	No	Yes	Yes	Yes	No
Greece	Household	No	Yes	Yes	No	No
	Small industrial	No	Yes	Yes	No	No
	Large industrial	No	Yes	Yes	Yes	Possible
Hungary	Household	Yes	No	Yes	Possible if the meter installed can measure the reactive power.	Yes, Loss charges
	Small industrial	Yes	No	Yes	Yes	Yes, Loss charges
	Large industrial	Yes	Yes	Yes	Yes	Yes, Loss charges
Ireland	Household	Yes	No	Yes	Yes	No
	Small industrial	Yes	No	Yes	Yes	No
	Large industrial	Yes	Yes	Yes	Yes	No
Italy	Household	Yes	Yes	Yes	No	Yes, Metering
	Small industrial	Yes	Yes	Yes	No	Yes, Metering
	Large industrial	Yes	Yes	Yes	No	Yes, Metering
Latvia	Household	N.A	N.A	N.A	No	N.A
	Small industrial	N.A	N.A	N.A	No	N.A
	Large industrial	N.A	N.A	N.A	No	N.A
Lithuania	Household	Yes, it is Possible	No	Yes	No	No
	Small industrial	No	Yes	Yes	No	No
	Large industrial	No	Yes	Yes	No	No
Luxembourg	Household	Yes	No	Yes	No	Yes, Metering
	Small industrial	No	Yes	Yes	No	Yes, Metering
	Large industrial	No	Yes	Yes	No	Yes, Metering
Malta	Household	Yes	No	Yes	No	No
	Small industrial	Yes	No	Yes	Yes	No
	Large industrial	Yes	No	Yes	Yes	No
Poland	Household	Yes	No	Yes	No	Yes, subscription

Country	Consumer group	Fixed Charge	Capacity charge	Energy charge	Energy reactive	Other
						fee (Metering)
	Small industrial	No	Yes	Yes	No	Yes, subscription fee (Metering)
	Large industrial	No	Yes	Yes	Yes	Yes, subscription fee (Metering)
Portugal	Household	No	Yes	Yes	No	No
	Small industrial	No	Yes	Yes	Yes	No
	Large industrial	No	Yes	Yes	Yes	No
Romania	Household	No	No	Yes	No	No
	Small industrial	No	No	Yes	No	No
	Large industrial	No	No	Yes	No	No
Slovakia	Household	No	Yes	Yes	No	Yes, distribution losses
	Small industrial	No	Yes	Yes	No	Yes, distribution losses
	Large industrial	No	Yes	Yes	No	Yes, distribution losses
Slovenia	Household	No	Yes	Yes	No	No
	Small industrial	No	Yes	Yes	No	No
	Large industrial	No	Yes	Yes	Yes	No
Spain	Household	No	Yes	Yes	No	Yes, Metering
	Small industrial	No	Yes	Yes	Yes	Yes, Metering
	Large industrial	No	Yes	Yes	Yes	Yes, Metering
Sweden	Household	Yes	No	Yes	No	No
	Small industrial	Yes	No	Yes	No	No
	Large industrial	Yes	No	Yes	No	No
The Netherlands	Household	Yes	Yes	No	No	No
	Small industrial	No	Yes	No	Yes	No
	Large industrial	No	Yes	Yes	No	No
Great Britain	Household	Yes	No	Yes	No	No
	Small industrial	Yes	Yes. It can apply if the small industrial consumer if they elect to move to HH settlement.	Yes	Yes. It can apply if the small industrial consumer if they elect to move to HH settlement.	No
	Large industrial	Yes	Yes	Yes	Yes	Yes, Excess Capacity charge

N.A: Information not available

Source: Prepared by authors based on information of each electricity country report according to consumer group definition (Table 3: Tariff components, customers and revenues per customer class). Situation in 2013. Belgium data based on Eurelectric paper: "Network tariff structure for a smart energy system"

Annex 3: Summary of gas distribution tariff components by consumer group

Country	Consumer group	Fixed Charge	Capacity charge	Energy charge	Other
Austria	Household	Yes, depending of annual consume	Yes, depending of annual consume	Yes	No
	Industrial	No	Yes	Yes	No
Belgium	Household	N.A	N.A	N.A	N.A
	Industrial	N.A	N.A	N.A	N.A
Bulgaria	Household	N.A	N.A	N.A	N.A
	Industrial	N.A	N.A	N.A	N.A
Croatia	Household	Yes	No	Yes	No
	Industrial	Yes	No	Yes	No
Czech Republic	Household	Yes	No	Yes	No
	Industrial	Yes	No	Yes	No
Denmark	Household	No	No	Yes	No
	Industrial	No	No	Yes	No
Estonia	Household	No	No	Yes	No
	Industrial	No	No	Yes	No
Finland	Household	Yes, varies depending on DSO	No	Yes, varies depending on DSO	No
	Industrial	Yes, varies depending on DSO	Yes, varies depending on DSO	Yes, varies depending on DSO	Yes, varies depending on DSO
France	Household	Yes	No	Yes	No
	Large industrial	Yes	Yes	Yes	No
Germany	Household	Yes, if the annual consumption of up to 1.5m kWh[1] and a maximum exit load of 500 kWh/h	Yes, if Annual consumption above 1.5m kWh/a	Yes	Yes, Metering
	Industrial	No	Yes	Yes	Yes, Metering
Greece	Household	N.A.			
	Industrial	N.A.			
Hungary	Household	Yes	No	Yes	Yes, Metering
	Industrial	No	Yes	Yes	Yes, Metering
Ireland	Household	No	Yes	Yes	No
	Industrial	No	Yes	Yes	No
Italy	Household	Yes	No	Yes	No
	Industrial	Yes	No	Yes	No
Latvia	Household	N.A	N.A	N.A	N.A
	Industrial	N.A	N.A	N.A	N.A
Lithuania	Household	No	No	Yes	No

Country	Consumer group	Fixed Charge	Capacity charge	Energy charge	Other
	Industrial	No	No	Yes	No
Luxembourg	Household	No	No	Yes	Yes, Metering
	Industrial	No	Yes	Yes	Yes, Metering
Poland	Household	No	Yes	Yes	No
	Industrial	No	Yes	Yes	No
Portugal	Household	Yes	No	Yes	No
	Industrial	Yes	Yes	Yes	No
Romania	Household	N.A	N.A	N.A	N.A
	Industrial	N.A	N.A	N.A	N.A
Slovakia	Household	Yes	No	Yes	No
	Industrial	Yes	Yes	Yes	No
Slovenia	Household	Yes	No	Yes	Yes. Metering
	Industrial	Yes	Yes	Yes	Yes. Metering
Spain	Household	Yes	No	Yes	No
	Industrial	No	Yes	Yes	No
Sweden	Household	Yes	No	Yes	No
	Industrial	Yes	No	Yes	No
The Netherlands	Household	Yes	Yes	No	Yes, Metering
	Industrial	Yes	Yes	No	No
Great Britain	Household	No	Yes	Yes	Yes, Metering
	Industrial	No	Yes	Yes	Yes, Metering

Source: Prepared by authors based on information of each electricity country report according to consumer group definition (Table 3: Tariff components, customers and revenues per customer class). Situation in 2013
1) The threshold of 1.5m kWh can be adjusted by the DSO
According to Greek regulator, there is not possible to understand the different tariff components used by a DSO to recover costs for distribution activities.

Annex 4: Summary of time of use differentiation in electricity distributions tariff by consumer group

	Time Differentiation			
Country	Household	Small Industry	Large Industry	Observations
Austria	Yes	Yes	Yes	There are four different tariff times for every network area (summer - high, summer - low, winter - high and winter - low); but just for consumers starting with network level 3.
Belgium	N.A	N.A	N.A	
Bulgaria	N.A	N.A	N.A	
Croatia	Yes	Yes	Yes	There are two different energy components in peak (8 – 21 hours) and off-peak (21 – 8 hours) times.
Cyprus	No	No	No	
Czech Republic	Yes	Yes	Yes	Daily differentiation: peaks and off-peaks. The start and end of off peak periods during the day are decided by each DSO based on grid conditions and activated via remote control system; the total duration of off-peaks per day has to amount to the value set out in the tariff specifications.
Denmark	No	No	Yes	No time of use differentiation except for large consumers with consumption above 100.000 kWh.
Estonia	Yes	Yes	Yes	Energy component has two options: Base tariff or time of use tariff (night-day)
Finland	No	Yes	No	Large LV customer may choose time-of-use tariffs based on

	Time Differentiation			
				day and night time of use or winter and summer time of use.
France	Yes	Yes	Yes	There is a time differentiation for all groups of consumers. HVA (between 50kW and 63kW): Three different tariffs are proposed. Two of them as per kW and per kWh components which are time differentiated. LV above 36kVA: Two different tariffs are proposed. One as both per kW and per kWh time differentiated component. The other as only per kWh time differentiated components. There is no flat tariff. LV up to 36kVA: Three different tariffs are proposed. One of them as per kWh time differentiated component (two index, intra-day time differentiation).
Germany	No	No	No	Normal tariffs have no time component. Atypical costumers are rewarded with lower tariffs if their peak load does not coincide with network peak load.
Greece	Yes	Yes	Yes	For example, electricity prices for night-time consumption are lower (i.e. not charged energy consumption at night time).
Hungary	No	No	No	
Ireland	Yes	Yes	Yes	There are energy component- time zone tariff (day or night) to consumers with day and night meter. To consumers with Standard meter have a 24h tariff. The night c/kWh rates are applicable to night storage heating, which is separately metered and controlled by a time switch.
Italy	No	No	No	
Latvia	N.A	N.A	N.A	
Lithuania	Yes	Yes	Yes	Households: There are two types of tariff, which can be chosen. The one time zone tariff and two time zones tariff. Commercial & Industrial customers: May choose 2 TOU tariffs: one, two or four time zone tariffs.
Luxembourg	No	Yes	Yes	
Malta	No	Yes	Yes	Non-residential consumers with consumption > 5000 MWh or 5500 MVAh (day/night): charged a day premium of €0.002 and a night discount of €0.035 over the applicable non-residential tariff.
Poland	Yes	Yes	Yes	The energy component is different in peak and off-peak time (2 or 3 time zones). The zones are defined in different way.
Portugal	Yes	Yes	Yes	The energy component is differentiated by time period (peak, half-peak, off-peak and super off-peak times) and seasonal period.
Romania	No	No	No	
Slovakia	Depends on DSO	Depends on DSO	Depends on DSO	For some DSO's no time of use differentiation and for some DSO per energy component is different in peak and off-peak times, in order to reflect the degree of utilization of shared distribution network assets.
Slovenia	Yes	Yes	Yes	Both components (for kW and Kwh) are different regarding time of use. In winter period tariffs are higher than in summer period. Component for kWh are time differential for working days. From 6 to 22 o'clock the tariff is higher. The rest of the hours (and in nonworking days) are defined as the low tariff. This applies for all group of consumers.
Spain	Yes	Yes	Yes	For Low Voltage tariff (< 1 kV) and contracted power mess than 15 kW, there are 1 time period or 2 energy time period and 3 energy time period with no time use differentiation in contracted power. Furthermore for also LV with contracted power higher than 15 KW, there is a 3 time period: energy and power time of use differentiation. For High Voltage (> 1 kV) : All tariff with 6 time period (energy and power)
Sweden	Depends on DSO	Depends on DSO	Depends on DSO	DSO´s decide and some are using tariffs differentiated according to time of use.
Netherlands	No	No	No	

	Time Differentiation			
Great Britain	Yes	Yes	Yes	There are a number of different tariff classes but the main four types are: Domestic: One or two rate (day or night) NHH metered (non-domestic): One or two rate (day or night) HH metered (LV, HV and HV substation): Three rate (red (peak) / amber / green) EHV HH metered: Super-red rate (per KWh)
Total Countries	12	15	15	

Source: Prepared by authors based on information of each electricity country report according to distribution tariff data.

Annex 5: Breakdown of electricity network annual charges by country – customer types

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013					
				Fixed (€)	Capacity (€)	Active Energy (€)	Reactive Energy (€)	Total (€)	Average network cost (cent €/kwh)
Austria	Household	Tariff of Residential grid level 7 not metered - Lower Austria region	Data provided by E-Control based on Electricity System Charges Ordinance 2013 http://www.e-control.at/portal/page/portal/medienbibliothek/recht/dokumente/pdfs/SNE-VO%20Novelle%202013_BGBL_II_481_2012.pdf			149		167	4,76
	Small Industrial	Tariff of Small commercial grid level 7 metered - Vienna region			1386	905	-	2291	4,58
	Large Industrial	Tariff of Industrial grid level 4 - Vienna region	Charges are segmented by time and geographical zone. Indicative values are provided for Vienna (industrial and commercial) and Lower Austria (residential), which are intermediate in the range.	-	106080	112968	-	219048	0,91
Belgium	Household								
	Small Industrial								
	Large Industrial								
Bulgaria	Household								
	Small Industrial								
	Large Industrial								
Croatia	Household								

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013					
				Fixed (€)	Capacity (€)	Active Energy (€)	Reactive Energy (€)	Total (€)	Average network cost (cent €/kwh)
	Small Industrial								
	Large Industrial								
Czech Republic	Household	Tariff D 02d; circuit breaker over 3x20A up to 3x25A, inclusive	Data provided by the Energy Regulatory Office (ERO)	28	-	234	-	262	7,49
	Small Industrial	Tariff C 02d; circuit breaker over 3x20A up to 3x25A, inclusive		1206	-	2121	-	3327	6,65
	Large Industrial	Industrial consumer, connected to MV		-	238001	73689	-	311690	1,30
Denmark	Household		Data not available according the National Regulator						
	Small Industrial								
	Large Industrial								
France	Household	CRE hypothesis: voltage level LV < 36 kVA, base tariff (no temporal differentiation), power contracted 6kV, usual metering system (for the metering component: power control through circuit breaker, variables measured through index, user is not the owner of the metering system; for the administrative management component: user has only one contract with his supplier - no direct contract with the DSO).		9	22	121	-	151	4,32

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013					
				Fixed (€)	Capacity (€)	Active Energy (€)	Reactive Energy (€)	Total (€)	Average network cost (cent €/kwh)
	Small Industrial	CRE hypothesis: voltage level LV > 36 kVA, Medium Usage, power contracted 40kV, usual metering system (for the metering component: power control through overshoot, variables measured through measurement curve, user is not the owner of the metering system; for the administrative management component: user has only one contract with his supplier - no direct contract with the DSO-)		69	475	1298	-	1842	3,68
	Large Industrial	CRE hypothesis: voltage level HVA, base tariff (no temporal differentiation), power contracted 3,450kV, usual metering system (for the metering component: power control through overshoot, variables measured through measurement curve, user is not the owner of the metering system; for the administrative management component: user has only one contract with his supplier - no direct contract with the DSO-).		69	74106	252896	-	327071	1,36
Estonia	Household			-	-	195	-	195	5,56
	Small Industrial			-	-	-	-	-	-
	Large Industrial			-	-	-	-	-	-
Finland	Household			163	-	209	-	372	10,63
	Small Industrial			67	1686	1941	-	3694	7,39
	Large Industrial			67	56046	643920	-	700033	2,92
Germany	Household	Low voltage consumer non measured. 3500 kWh. Data on tariff structures	The average network cost includes transmission revenues. Transmission costs are not charged separately but are part of distribution tariffs. On	40		188	0	228	6,52

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013					
				Fixed (€)	Capacity (€)	Active Energy (€)	Reactive Energy (€)	Total (€)	Average network cost (cent €/kwh)
		were only available for DSOs in BNetzA responsibility	the LV average share is very roughly about 5%-15% Tariff components are calculated of the average shares for the consumer groups from these BNetzA regulated DSOs. The average network cost per energy is taken from the "Monitoringbericht 2014" and is calculated as an average of all german DSOs.						
	Small Industrial	Low voltage costumer non measured. 50000 kWh and 50 KW. Average costs for all DSOs are only available for the national tariff reference. The given case hence differs from the small industrial consumer case listed above. The average includes measured and non measured consumers. Data on the share of measured consumers is not available	The given average network cost include transmission revenues. Transmission costs are not charged separately but are part of distribution tariffs. The share of transmission costs within the distribution revenues can only very roughly be approximated and can vary greatly from DSO to DSO. On the low voltage level average share is very roughly about 5%-15%. Data on tariff structures were only available for DSOs in BNetzA responsibility. The given shares for fixed, capacity and energy charges are calculated of the average shares for the consumer groups from these BNetzA regulated DSOs. Hereby only the typical case of non measuered (small industrial) consumers was taken into account. The average network cost in cent €/kWh is taken from the "Monitoringbericht 2014" and is calculated as an average of all german DSOs.	41	0	2764	0	2805	5,61
	Large Industrial	Measured MV consumer usage hours above 2500.	The given average network cost include transmission revenues. Transmission costs are not charged separately but are part of distribution tariffs. The share of transmission costs within the distribution revenues can only very roughly be approximated and can vary greatly from DSO to DSO. On the medium voltage level average share is	840	248695	180065		429600	1,79

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013					
				Fixed (€)	Capacity (€)	Active Energy (€)	Reactive Energy (€)	Total (€)	Average network cost (cent €/kwh)
			very roughly about 15-30%. Average network costs for distribution only could not be calculated from these value. Data on tariff structures were only available for DSOs in BNetzA responsibility. The given shares for fixed, capacity and energy charges are calculated of the average shares for the consumer groups from these BNetzA regulated DSOs. The average network cost in cent €/kWh is taken from the "Monitoringbericht 2014" and is calculated as an average of all German DSOs.						
Greece	Household	Residential tariff	Data provided by the Regulatory Authority for Energy (RAE).		5	71	-	76	2,17
	Small Industrial	LV w. reactive power metering			126	795	-	921	1,84
	Large Industrial	MV tariff			57216	69600	-	126816	0,53
Hungary	Household	"KIF I." (LV I)	Data provided by Hungarian Energy and Public Utility Regulatory (MEKH)	6	0	141	0	147	4,20
	Small Industrial	"KIF III." (LV III)	Authority1092/2012. HEO Resolution and 4/2013. HEA Decree	119	1012	1284	1	2415	4,83
	Large Industrial			356	102131	233231	44	335762	1,40
Ireland	Household								
	Small Industrial								

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013					
				Fixed (€)	Capacity (€)	Active Energy (€)	Reactive Energy (€)	Total (€)	Average network cost (cent €/kwh)
	Large Industrial								
Italy	Household		Data provided by the National Regulator. Because of the regime of progressivity , the components of the D2 and D3 tariffs do not allow to distinguish the relative shares of the various regulated services (Trans. , dist. , measure) was made an estimate based on the data tariff reference D1. Capacity charge includes the value of the component UC6. Energy charge includes the value of the components UC3 and UC6	6	17	118	-	141	4,03
	Small Industrial		Data provided by the National Regulator. Fixed charge includes the value of the MIS and the fixed component UC6. Energy charge includes the value of the components TRAS , UC3 and UC6.	7	629	184	-	820	1,64
	Large Industrial		Provided by the National Regulator. Fixed charge includes the value of the MIS and the fixed component UC6. Energy charge includes the value of the components TRAS , UC3 and UC6.	563	12784	42480	-	55827	0,23
Lithuania	Household								

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013					
				Fixed (€)	Capacity (€)	Active Energy (€)	Reactive Energy (€)	Total (€)	Average network cost (cent €/kwh)
	Small Industrial								
	Large Industrial								
Luxembourg	Household	LV not metered final customer.	Consultant estimates on Creos tariffs as approved for the year 2013 by the NRA	24	-	211	-	235	6,71
	Small Industrial	Final customers 65 kV, 10 kW demand, > 3000 h/year time of use.	Consultant estimates on Creos tariffs as approved for the year 2013 by the NRA	1,136	200	250	-	1586	3,17
	Large Industrial	Final customers 220 kV, 5000 kW, 7000 h/year time of use.	Consultant estimates on Creos tariffs as approved for the year 2013 by the NRA	-	183450	52800	-	236250	0,98
Malta	Household		Data provided by the National Regulator.						2,20
	Small Industrial		This is an overall average per kWh of all network cost charges-fixed and €/kWh components.						2,20
	Large Industrial								2,20
Poland	Household			56	-	148	-	204	5,83
	Small Industrial			1250	-	709	-	1959	3,92
	Large Industrial			2427	11059	244255	-	257741	1,07
Portugal	Household		Data provided by the National Regulator (ERSE)	41	-	68	-	109	3,11

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013					
				Fixed (€)	Capacity (€)	Active Energy (€)	Reactive Energy (€)	Total (€)	Average network cost (cent €/kwh)
	Small Industrial		Network tariffs are determined and approved by the NRA. These tariffs are one of 3 components of the TPA tariff, which results from adding each of the previous. TPA tariff includes: 1) Distribution network tariff (used here), 2) transmission network tariff and 3) global use of the system (which accounts for several type of levies, e.g. renewable support costs).	255	781	160	-	1196	2,39
	Large Industrial			10739	92168	21022	-	123929	0,52
Romania	Household		Data provided by the National Regulator	0	-	159	-	159	4,55
	Small Industrial			0	-	700	-	700	1,40
	Large Industrial			0	-	114240	-	114240	0,48
Slovakia	Household	Tariff D2	Data provided by the Regulatory Office for Network Industries (RONI)	58	-	109	-	168	4,79
	Small Industrial	Tariff C3; circuit breaker over 3x50A up to 3x63A, inclusive because capacity 35 kW		-	606	2424	-	3030	6,06
	Large Industrial	Industrial consumer, connected to MV		-	239098	277844	-	516941	2,15
Slovenia	Household			-	56	135	-	191	5,46

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013					
				Fixed (€)	Capacity (€)	Active Energy (€)	Reactive Energy (€)	Total (€)	Average network cost (cent €/kwh)
	Small Industrial			-	1938	998	-	2936	5,87
	Large Industrial			-	152949	173280	-	326229	1,36
Spain	Household	Household (Sin DH) (1P) with a Power contracted of 3,5KW (15A) Tariff 2.0 (Only distribution tariff)	Memo of Notice (Circular) 3/2004 (July 2) by National Commission of Markets and Competition (CNMC) , Establish the methodology for the calculation of Tariff access for transport and distribution of Electricity (02 /07/ 2014) http://www.cnmc.es/Portals/0/Ficheros/Energia/Circulares/Circular_3_2014/03_2014_Circular_memoria.pdf Table 47 Pag 73	-	78	15	-	93	2,66
	Small Industrial	Small industrial LV with a Power contracted of 35KW. Tariff 3.0 TD (Only distribution tariff)		-	780	200	-	980	1,96
	Large Industrial	Industrial consumer (NT3) with a Power contracted of 3429 KW. Tariff 6.3 TD (Only distribution tariff)		-	36657	22135	-	58792	0,24
Sweden	Household	Average of DSO tariffs of Consumer with an annual consumption of 5 000 kWh/year and 16A. Data at January 1, 2014.	Fixed component: include DSO average of regulatory fees (54 SEK/ 6 €) and fixed fees (2066 SEK / 239€). Energy component: based on DSO average (0.1595 SEK /KWh, 0.0184 €/KWh). Calculate the energy	245	-	65	-	310	8,86

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013					
				Fixed (€)	Capacity (€)	Active Energy (€)	Reactive Energy (€)	Total (€)	Average network cost (cent €/kwh)
			component 3,500KWh X 0.0184 €/KWH Exchange rate: 1eur= 8,6515 SEK Average 2013 according European Central Bank						
	Small Industrial	Average of DSO tariffs of Consumer with an annual consumption of 30 000 kWh/year and 26A. Data at January 1, 2014.	Fixed component: include DSO average of regulatory fees (54 SEK/ 6 €) and fixed fees (4026 SEK / 465€). Energy component: based on DSO average of 2 type of fees. Energy charge1 (0.1577 SEK/KWh, 0.01820 €/KWH), Energy charge 2 (0.111 SEK/KWh, 0.01239 €/KWH). Calculate of the energy component 50,000 KWh X 0.0155 €/KWH (Average of 2 energy fees)	471	-	777	-	1248	2,50
	Large Industrial	Average of DSO tariffs of Consumer with an annual consumption of 50Ghz and 1MW. Data at January 1, 2014.	Fixed component: include DSO average of regulatory fees (2800 SEK/ 324 €) and fixed fees (14954 SEK / 1729€). Capacity component: based on DSO average and 50% in Power charge off-peak (170 SEK/KW/year, 20€/KW/year) and 50% Power Charge peak (141 SEK/KW/year, 16€/KW/year) for a total of 18€/KW/Year. Calculate the capacity component 4,000 KW/year X 18€/KW/year. Energy component: based on DSO average of 4 type of fees. Energy charge winter peak (0.0456	2052	71824	104044	-	177920	0,74

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013					
				Fixed (€)	Capacity (€)	Active Energy (€)	Reactive Energy (€)	Total (€)	Average network cost (cent €/kwh)
			SEK/KWh, 0.00527 €/KWH), Energy charge winter off peak (0.0346 SEK/KWh, 0.00400 €/KWH), Energy charge summer peak (0.0353 SEK/KWh, 0.00408 €/KWH) and Energy charge summer off peak (0.0344 SEK/KWh, 0.00399 €/KWH). Calculate of the energy component 24 Gown X 0.00433 €/KWH (Average of 4 energy fees)						
The Netherlands	Household			215	-	-	-	215	6,14
	Small Industrial							1817	3,63
	Large Industrial			113441	-	125000	-	238441	0,99
Great Britain	Household			18	-	114	-	132	3,77
	Small Industrial			140	-	1467	-	1607	3,21
	Large Industrial			303	81934	253258	-	335495	1,40

Household consumer with an annual consumption of 3500 kWh connected to the low voltage grid and a contracted capacity of 6 KW.
Small industrial consumer with an annual consumption of 50000 kWh connected to the low voltage grid and a contracted capacity of 35 KW.
Large industrial with an annual consumption of 24000 MWh and 7000 use hours connected to the medium voltage grid and a contracted capacity of 4000 KW.

Annex 6: Breakdown of gas network annual charges by country – customer types

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013				
				Fixed (€)	Capacity (€)	Energy (€)	Total (€)	Average network cost (cent €/kwh)
Austria	Household		Data provided by E-Control based on Gas System Charges Ordinance 2013 http://www.e-control.at/portal/page/portal/medienbibliothek/recht/dokumente/pdfs/GSNE-VO%202013%20konsolidierte%20Fassung%2027.12.2012.pdf	30	-	229	259	1,73
	Industrial consumer (50GWh)			-	28284	160042	188326	0,38
	Industrial consumer (90 GWh)			-	58186	144740	202926	0,23
Belgium	Household							
	Industrial consumer (50GWh)							
	Industrial consumer (90 GWh)							
Bulgaria	Household							
	Industrial consumer (50GWh)							
	Industrial consumer (90 GWh)							
Croatia	Household							
	Industrial consumer (50GWh)							
	Industrial consumer (90 GWh)							
Czech Republic	Household		Data provided by the Energy Regulatory Office (ERO)	53	-	98	151	1,01
	Industrial consumer (50GWh)			-	80349	28180	108529	0,22
	Industrial consumer (90 GWh)			-	132701	50274	182975	0,20

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013				
				Fixed (€)	Capacity (€)	Energy (€)	Total (€)	Average network cost (cent €/kwh)
Denmark	Household		Data not available according the national regulator					
	Industrial consumer (50GWh)							
	Industrial consumer (90 GWh)							
Estonia	Household		Data provided by the national regulator through questionnaire. Network tariffs for all customers in network area are same. There is only an energy component. Largest DSO (86% of all) tariff is 0,03858 €/m^3	-	-	50	50	0,33
	Industrial consumer (50GWh)			-	-	165864	165864	0,33
	Industrial consumer (90 GWh)			-	-	298555	298555	0,33
Finland	Household							
	Industrial consumer (50GWh)							
	Industrial consumer (90 GWh)							
France	Household		Data provided by CRE. http://www.cre.fr/documents/deliberations/decision/tarif-de-distribution-de-gaz-de-grdf	120	-	108	228	1.52
	Industrial consumer (50GWh)			13737	30631	35500	79868	0,16
	Industrial consumer (90 GWh)			13737	55135	63900	132772	0,15
Germany	Household		Data not available according the national regulator					
	Industrial consumer (50GWh)							
	Industrial consumer (90 GWh)							
Greece	Household		Data not available according the national regulator					
	Industrial consumer							

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013				
				Fixed (€)	Capacity (€)	Energy (€)	Total (€)	Average network cost (cent €/kwh)
	(50GWh)							
	Industrial consumer (90 GWh)							
Hungary	Household		Data not available according the national regulator					
	Industrial consumer (50GWh)							
	Industrial consumer (90 GWh)							
Ireland	Household							
	Industrial consumer (50GWh)							
	Industrial consumer (90 GWh)							
Italy	Household			43	-	80	123	0,82
	Industrial consumer (50GWh)			43	-	27780	27823	0,06
	Industrial consumer (90 GWh)			43	-	39889	39932	0,04
Lithuania	Household		Data provided by the National Regulator http://www.lietuvosdujos.lt/index.php/gas-distribution-system-/natural-gal-distrubution-tariffs/248?year=2013	-	-	102	102	0,68
	Industrial consumer (50GWh)			-	-	250000	250000	0,50
	Industrial consumer (90 GWh)			-	-	304218	304218	0,34
Luxembourg	Household			-	-	111	111	0,74
	Industrial consumer (50GWh)			-	38993	173254	212247	0,42
	Industrial consumer (90 GWh)			-	57185	308218	365403	0,41
Poland	Household							
	Industrial consumer							

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013				
				Fixed (€)	Capacity (€)	Energy (€)	Total (€)	Average network cost (cent €/kwh)
	(50GWh)							
	Industrial consumer (90 GWh)							
Portugal	Household		Data provided by the National Regulator (ERSE)	29	-	507	536	3,57
	Industrial consumer (50GWh)		Network tariffs are determined and approved by the NRA. These tariffs are one of 3 components of the TPA tariff, which results from adding each of the previous. TPA tariff includes: 1) Distribution network tariff (used here), 2) transmission network tariff and 3) global use of the system (which accounts for several type of levies)	5116	118557	35748	159421	0,32
	Industrial consumer (90 GWh)			5116	213403	64346	282865	0,31
Romania	Household							
	Industrial consumer (50GWh)							
	Industrial consumer (90 GWh)							
Slovakia	Household		Data provided by the National Regulator (URSO)	50	15	140	205	1,37
	Industrial consumer (50GWh)			45145	82254	22,939	150,338	0,30
	Industrial consumer (90 GWh)			45145	148057	41,291	234,493	0,26
Slovenia	Household			48	-	123	171	1,14
	Industrial consumer (50GWh)			-	55227	342,989	398,216	0,80
	Industrial consumer (90 GWh)			-	62089	338660	400749	0,45
Spain	Household	Tariff 3.2 and a contracted capacity of 116KWh/day. Include network transmission access tariff.	Tariff access price based on: Orden IET/2812/2012 27/12/2012 In the Spanish gas system, consumers pay a single access tariff for the use of the transmission and distribution network. There is no a tariff for the use of the transmission network and a tariff for the distribution	81	-	322	403	2,69
	Industrial consumer (50GWh)	Tariff 2.4 and a yearly load factor of 7000 hours					159500	0,32

Country	Consumer group	National Tariff reference	Sources/ Observations	Average distribution network cost for the year 2013				
				Fixed (€)	Capacity (€)	Energy (€)	Total (€)	Average network cost (cent €/kwh)
	Industrial consumer (90 GWh)	Tariff 2.4 and a yearly load factor of 5157 hours. Include network transmission access.	network	188427	-	98640	287067	0,32
Sweden	Household		Data provided by the National Regulator	122	-	417	539	3,59
	Industrial consumer (50GWh)			213	-	1085000	1085213	2,17
	Industrial consumer (90 GWh)			213	-	1953000	1953213	2,17
The Netherlands	Household		Data provided by the National Regulator	18	127	-	145	0,97
	Industrial consumer (50GWh)							
	Industrial consumer (90 GWh)							
Great Britain	Household							
	Industrial consumer (50GWh)							
	Industrial consumer (90 GWh)							

Household consumer with an annual consumption of 15000 kWh.
Industrial consumer with an annual consumption of 50000000 kWh and 7000 use hours.
Industrial consumer with an annual consumption of 90000000 kWh and 7000 use hours.

Annex 7: Allowed electricity distribution revenues across EU Member states in 2013. (Include only distribution activities). Do not include transmission costs, taxes and levies

Country	Voltage level	Connection points	Total of electricity delivered (MWh)	Distribution circuit length (Km)	Total Allowed revenues (€)	Total Allowed revenues excluding losses (€)	Distribution (€)	Metering (€)	Customer Service & Administrative (€)	Distributions Losses (€)	Other	Observations
Austria	HV	550	18025000	9760	92369850		77871200					Customer Service revenues are included in Distribution revenues. Other are Costs for monition, disconnection fees etc. and have a social component (thus are not cost reflective)
	MV	30200	19102000	65550	443375280		373781760					
	LV	5731000	24930000	160300	1293177900		1090196800					
	Total	5761750	62057000	235610	1847397000	1734551000	1557424000	171521000		112846000	5,606000	
Croatia	MV	2126	3507000		64389563							
	LV	2349239	10878000		364,874,188							
	Total	2351365	14385000	-	429263750	429263750	382567161	46696590				
Cyprus	MV	646		8788								
	LV	512972		13640								
	Total	513618		22428	91964000	91964000						
Czech Republic	HV	127	6401368	12258	205194315		172654807	389711	6937161	32149797		Exchange rate average 2013: 25,974 CZK/EUR Total Allowed revenues include distribution losses.
	MV	25433	22168303	71713	551111898		479487837	6202035	17238139	65422026		
	LV	5837922	23809058	137470	667634937		468352302	82856607	29383281	116426028		
	Total	5863482	52378729	221441	1423941149	1263501879	1120494946	89448352	53558581	213997851		
Denmark	HV			1743								Total allowed revenues do not include revenues for energy saving activities
	MV			73983								
	LV			96093								
	Total	3277000	36802894	171819	903668042	903668042						
Estonia	MV			26000								
	LV			34000								
	Total	560381	8000000	60000	274040000	274040000						
Finland	HV	117		6622								
	MV	3761		138153								
	LV	3305268		237996								

Country	Voltage level	Connection points	Total of electricity delivered (MWh)	Distribution circuit length (Km)	Total Allowed revenues (€)	Total Allowed revenues excluding losses (€)	Distribution (€)	Metering (€)	Customer Service & Administrative (€)	Distributions Losses (€)	Other	Observations
	Total	3309146	60000000	382771	1550000000	1550000000						
France	HV		162800000	608053	3956957022			197229608	27747610			Connection points according CRE forecast 2013. Distribution revenues exclude losses. “Other” is the amount of transmission grid access grid.
	MV		189000000	685413	8310045030			636554086	300587374			
	LV											
	Total	34838361	351800000	1293466	12267002052	9332113907	8169995228	833783695	328334983	1157708794	3355487305	
Germany	HV	3923		96084								Data on connection points is not available. The values used here are the number of measurement points in the grid. Also only aggregated values over all voltage levels are available for all German DSOs. **Allowed revenues, distributions, metering and customer service data is not complete**. There is revenues data available for DSOs in responsibility of Bundesnetzagentur. The share of revenues of DSOs regulated by BNetzA from total revenues is roughly **85-90%** and can vary from year to year. The data is based on planned values. The revenues are not approved as the final formal approval of revenues including volatile costs and permanent not controllable costs is only commenced with approval of revenues in
	MV	72336		509866								
	LV	39714305		1156785								
	Total	49934777	469600000	1762735	12982849654	12982849654	11783229974	625782338	573837341			

Country	Voltage level	Connection points	Total of electricity delivered (MWh)	Distribution circuit length (Km)	Total Allowed revenues (€)	Total Allowed revenues excluding losses (€)	Distribution (€)	Metering (€)	Customer Service & Administrative (€)	Distributions Losses (€)	Other	Observations
Greece	HV			777								3RD regulatory Period starting from 2019. Revenue data do not contain revenues for elements that are not within network charges but are passed through by the DSO (e.g. concession fee, renewable energy support levy). Total allowed revenues have been reduced by the amount of upper grid charge to avoid double counting of costs (and inclusion of transmission costs in revenue figures).
	MV	11207	10865762	109686	66295162		64313052				1982111	
	LV	7381515	33276044	123352	710468512		689226732				21241780	
	Total	7392722	44141806	233815	776763674	776763674	753539784				23223890	
Hungary	HV	135	5050000	7872	16778720							Data of connection points and electricity delivered from 2012 Average HUF / eur rate 2013: 296,8730HUF/Eur . Source: European Central Bank. Other include: local taxes, public authority fees, transfer costs
	MV	6209	9479000	66816	166787833							
	LV	7246562	19428000	87266	737305018							
	Total	7252906	33957000	161954	920871572	687432260	518814034	78969107	63504769	233493784	26144350	
Ireland	HV	6		538								
	MV	1545		97790								
	LV	2235681		69200								
	Total	2237232	23000000	167528	729000000	729000000						
Italy	MV			342600								

Country	Voltage level	Connection points	Total of electricity delivered (MWh)	Distribution circuit length (Km)	Total Allowed revenues (€)	Total Allowed revenues excluding losses (€)	Distribution (€)	Metering (€)	Customer Service & Administrative (€)	Distributions Losses (€)	Other	Observations
	LV			762616								
	Total	37099007	264000000	1105216	5650000000	5650000000						
Lithuania	MV			54017	34600000							Distribution revenues in 2013 were 450,69 (130,53 million EUR, when 1 EUR=3.4528 LTL). MV revenue was 34,6 million EUR (26%), LV revenue – 96 million EUR (74%).
	LV			69732	96000000							
	Total	1619530	8040000	123749	130600000	130600000						
Luxembourg	HV			-								
	MV			3160								
	LV			5318								
	Total	281428	5040000	8478	162250000	162250000						
Malta	HV			48								
	MV			1400								
	LV			2847								
	Total	285214	2132990	4295		29003000	29003000					
Poland	HV	379	24109000	32671	316140560							Planned revenue for 2013 in tariffs of 5 biggest DSOs Currency rate Average 2013: 1 eur= 4,1975 PLN Source European Central Bank
	MV	34518	43209000	305492	992257296							
	LV	16775752	54066000	435978	2931983323							
	Total	16810649	121384000	774141	4240381179	4240381179						
Portugal	HV	280	6648000	-	12796670							There is no separate determination of network cost allowance. More so, the total allowed revenues include cost items which hardly derive from "regular" DSO technical activity like concession fees for LV network.
	MV	23538	13793000	83256	204746720							
	LV	6061698	21322000	139371	1049326940							
	Total	6085516	41763000	222627	1279667000	1279667000						

Country	Voltage level	Connection points	Total of electricity delivered (MWh)	Distribution circuit length (Km)	Total Allowed revenues (€)	Total Allowed revenues excluding losses (€)	Distribution (€)	Metering (€)	Customer Service & Administrative (€)	Distributions Losses (€)	Other	Observations
												As consequence of Portuguese legislation, the meters cannot be remunerated in any way, nor charged separately to the customers. Hence the meter assets (only the devices on customer permisses) are not a part of the RAB. Other metering related costs are not treated separately from other cost items. Energy losses are provided by each market agent as they must procure in the wholesale market an energy quantity which is the consumption plus an added percentage for losses. This percentage is adjusted to account the actual losses verified in the transmission and distribution networks. Hence there is no cost allowance to the DSO to procure losses. Besides this, there is an incentive mechanism for the DSO to promote overall losses reduction.
Romania	HV	256	7441406	6584								
	MV	17852	13438200	34665								
	LV	8824027	20124416	48695								
	Total	8842135	41004022	89944	1140000000	1140000000						
Slovakia	HV	96	3172000	6743	19433445							
	MV	12944	7710000	32361	177117554							
	LV	2421057	7683000	52250	318925001							

Country	Voltage level	Connection points	Total of electricity delivered (MWh)	Distribution circuit length (Km)	Total Allowed revenues (€)	Total Allowed revenues excluding losses (€)	Distribution (€)	Metering (€)	Customer Service & Administrative (€)	Distributions Losses (€)	Other	Observations
	Total	2434097	18565000	91354	515476000	515476000						
Slovenia	MV	1530	4485266	17422	40440248							
	LV	931505	5833844	46718	212438426							
	Total	933035	10319110	64140	252878674	252878674						
Spain	HV	2572	49127000	31380			99574000	5093				Revenues data for 2014.
	MV	105591	70703000	280345			1024527000	209070				Metering include commercial cost.
	LV	28592609	114669000	383202			3828944000	56613366				
	Total	28700772	234499000	694927	5069743000	5069743000	4953646000	56827529				
Sweden	HV											
	MV	7081	28235857	197024								
	LV	5358028	66651246	312044								
	Total	5365109	94887103	509068	4965480341	4965480341	4374181579	159905000		190038731	431393762	
Netherlands	MV	32935	44690000	104592	1220000000			No regulatory tariffs apply				Distribution revenues include distribution losses
	LV	8119161	64310000	145213	1990000000			210000000				
	Total	8152096	109000000	249805	3210000000	2994018606	3000000000	210000000	215981394			
Great Britain	HV			75440								Average currency rate 2013: EUR 1 = GBP 0,84926
	MV			352841								
	LV			408875								
	Total	29907234	355340000	837156	6265454631		6201869863	63584768				

Annex 8: Allowed gas distribution revenues across EU Member states in 2013.
(Include only distribution activities). Do not include transport costs, taxes and levies

Country	Connection points	Total of energy delivered (MWh)	Total Allowed revenues (€)	Distribution (€)	Metering (€)	Customer Service & Administrative (€)	Others (€)	Observations
Austria	1349012	94000000	547154245	541600000	24552014			
Croatia	651099	10646000	61959437					
Czech Republic	2860345	86346200	564000000	278953935	43710677	22938878	22053971	
Denmark	-	41370000	201000000					
Estonia			25500000					
Finland		33200000	72000000					
France	11027387	327000000	3300000000	3138500000	161500000			
Germany	10564000	739000000	4500000000					Allowed revenue for DSO within the responsibility of the BNetzA. The allowed revenues of DSOs within the responsibility of the Federal States are unknown.
Greece	307060	8490219						Allowed revenues are not available according the national regulator
Hungary	3057779	74847608	278357213	247591846	36164	30729204		Exchange rate: 296,8730 HUF/EUR Metering only include the cost of meter reading.
Ireland	657000	13955000	185200000	129640000	37040000		18520000	
Italy	21523072	355722266	3200000000					Data provided by the National regulator. Correction factor used: 0,01170 MWh/SCM
Lithuania	561554	8899179	48860924					
Luxembourg	84277	11276014	33460000					
Poland	6471100	159541200	954000000					
Portugal	1341037	25153000	301609000					There is no separate determination of network cost allowance. Contrary to the electricity sector, the total allowed revenues do not include concession fees which are

Country	Connection points	Total of energy delivered (MWh)	Total Allowed revenues (€)	Distribution (€)	Metering (€)	Customer Service & Administrative (€)	Others (€)	Observations
								charged to consumers separately to the network tariff. Metering. As consequence of Portuguese legislation, the meters cannot be remunerated in any way, nor charged separately to the customers. Hence the meter assets (only the devices on customer permisses) are not a part of the RAB.
Slovakia	1510749	53726699	380968346	205652033	37504645	5601495	12673	
Slovenia	132806	3478465	50820000	42630000	3350000	4840000		
Spain	7388850	168224224	1475271000					According to the memory of the proposal of the CNMC to establish a access tariff methodology (table 23, page 47), the number of connection points in 2013 was 7388850 and total of energy delivered was 168224224 MWh Data includes also transmission activities
Sweden	37385	9805699	83759349					
The Netherlands	7194105	526500000	1271000000	1131000621	140445500			
Great Britain		916110000	3291000000	3237800000	53800000			

7. Task 6 - Recommendations to the Commission

In this chapter we present recommendations to the Commission based on the findings of our investigation of various aspects of the Member States' regulation of electricity and gas distribution. Our survey of the regulatory frameworks implemented in the Member States highlights that:

- The existing regulatory frameworks for electricity and gas distribution appear to be well tailored to the traditional role and technology of distribution networks;
- Multiple indications point at an evolving role of distributors, in particular in electricity.

Two caveats are in order at this point. First, recommendations cannot be cast in terms of individual tools or mechanisms, as multiple features of the regulatory framework interact to determine its outcome in terms of incentives for regulated firms and cost to consumers.

Second, some features of optimal regulatory models depend on the content of distributors' activity, which in Europe will be shaped by policies that are still being developed, for example on electric mobility and on commercial arrangements to exploit small consumers' demand flexibility .

The existing regulation of electricity and gas distribution tariffs is in most Member States consistent with the traditional features of the distribution business, i.e.:

- Little generation connected to distribution networks and inflexible demand, so that the primary role of distribution consists in transferring a basically unidirectional power from the transmission network to the consumers' premises, trough relatively passive networks;
- The distributor's main "outputs" are ensuring universal access to the service or a target network coverage, respectively for electricity and gas, and continuity of supply;
- Consolidated technology and network planning methodologies, implying limited uncertainty optimal investment decisions and ease of auditing by regulators;
- Very diverse industry structures among Member States, with high fragmentation in some countries.

Those features of the distribution business appear to be reflected in the regulatory systems currently implemented in most European countries. In particular:

- With the exception of Great Britain, current incentive-based regulatory schemes place little emphasis on characterizing the outputs delivered by the distributor, but for quality of service schemes in some countries;
- Typically distributors are not exposed to volume risk and to the risk that their investment, for example because of lower than expected demand, turn out to be less useful than expected when they were decided;

- Revenue setting mechanisms based on benchmarking are implemented in countries where the distribution sector is highly fragmented;
- Regulators and stakeholders are generally less involved in the decision-making process on distribution network development, compared to transmission;
- Traditional tariff structures reflect limited availability of information on each consumer's responsibility in causing the distribution system's peak and by affordability and fairness considerations.

Next we discuss the main trends that European distribution business is undergoing and their implications for tariff regulation.

An investment cycle is being spurred by the need to increase the distribution network's capacity to host an expanding fleet of renewable generators. Future investments appear to depart from traditional distribution upgrades in several respects:

- They involve innovative technologies whose cost and performances are more uncertain and on which information asymmetries between regulators and firms might be greater;
- Multiple options to achieve the same results are available, such as deployment of storage capacity in alternative to increasing demand response, upgrading lines and substations or deploying smart technologies, distributing or centralising network intelligence, developing new telecommunication infrastructures or exploiting existing ones;
- Distribution investment decisions interact with the outcome of decisions in areas beyond the distributors' control, such as renewable production targets or national deployment strategies of IT infrastructures.

Regulatory frameworks that, in our view, are most effective in the new environment share the following features, which we present next in the form of recommendations.

Recommendation 1: Distributors should not be exposed to risks related to events that are not under their control. This implies, in particular, that distributors do not be exposed to:

- Volume risk given their limited control on power and gas consumption; this is a feature of regulatory schemes already deployed in most Member States.
- The risk of cost under-recovery in case investments turn out to be ex-post less useful than expected.

The downside of the latter feature is, *ceteris paribus*, less incentives for distributors to select the efficient investment strategy[53]. However, such negative impact on the quality of distributor's investment decisions can be more than offset by greater ex-ante scrutiny, which leads us to the next recommendation.

Recommendation 2: major distribution network investment decisions should be subject to structured and open ex-ante scrutiny by stakeholders and regulators. A transparent and open process to assess the investment's opportunity should be implemented,

[53] This is particularly could result even result incentives to distort investments if other

including publication of cost benefit analyses by the distributors, public consultation, independent technical audit and, finally, some form of regulatory approval.

The outcome of such process would be a thoroughly audited investment strategy which consumers could be safely required to undertake the risk of. In addition, an open and inclusive decision-making process would ease coordination of distribution investment decisions and the outcomes of related decision making streams. For example, as part of this process:

- The implications of alternative investment options in terms of generation hosting capacity at different locations should be assessed;
- Distributors should be required to consider, assess and consult stakeholders about any opportunities to exploit synergies with other sectors, and in particular with suppliers of non-energy local services. Such synergies, for example, could result from:
    - Distributors procuring telecommunication services from existing providers;
    - Distributors granting access to passive infrastructures to telecommunication service providers
    - Distributors sharing the services of IT infrastructures built for their purposes with other users - such as suppliers of street lighting, traffic control or waste collection services.

Complex investment approval proceedings may place an unjustified administrative burden on small distributors and, if the distribution sector is highly fragmented, on the regulator; such cost would ultimately be passed on to consumers via distribution tariffs. Arrangements to mitigate administrative costs are conceivable; for example, in case one large distributor and several small distributors operate in geographical area, the larger distributor could act as the aggregator of the smaller distributors' investment plans in order to ensure consistency of the plans submitted to the regulator. Further, streamlined scrutiny processes, possibly boiling down just to transparency requirements, could be envisaged for investment plans meeting certain predefined conditions, set by the regulator for example via benchmarking.

Financial incentives have proved very effective in aligning the distributors' objectives with the regulator's and, ultimately, the consumers' and can be expected to be core elements of effective regulatory schemes in the future. Incentive-based mechanisms place some risk on the regulated firms and the optimal balance between risk and incentive power is to be assessed on a case by case basis. In Recommendation 1 we have addressed the two perhaps most important sources of risk for distributors, arguing in favour of shielding distributors from their effects. However, incentive based mechanisms have and can be effectively implemented in order to steer the distributors' behavior in areas such as cost minimisation and quality of service.

The next recommendation focuses on these mechanisms.

Recommendation 3: The following features increase the power or reduce the cost for consumers of incentive-based regulatory schemes:

- Use of all available information on the efficient costs of distributors: the more information are available to the regulator on the distributor's efficient cost, the smaller the economic rents that need to left with distributors in order to align their objectives with the regulator's. Multiple sources of information are and should be used by regulators, including benchmarking analyses, technical audits, standard costing exercises. The Commission should promote publication of information and data about technical features, revenue setting methodologies, output targets and allowed revenues set for distributors in all Member States. Cost unbundling of activities for which a large part of costs can be assessed in isolation – such as metering – should be promoted, as this improves the quality of the information which incentive schemes can be based on.

- Focus on outputs: multiple performance dimensions, or outputs, have to be addressed by incentive-based regulatory schemes as distributors acquire increasing responsibilities in areas such as system operations, facilitation of retail competition, smart metering and energy conservation. Effective financial incentives in this context can be provided via premiums and penalties related to the achievement of pre-determined output targets. Targets should be selected such that they directly impact on the value of the service delivered by the distributor for network users' and, ultimately, consumers. We note incidentally that output based mechanisms can be implemented on top of a baseline tariff and investment scenario approved by the regulator along the lines of Recommendation 2.
- Focus on total cost and long regulatory periods: setting allowed revenues in terms of total costs provides incentives to distributors to select the efficient combination of operating and capital costs and to exploit any opportunities to create synergies with other sectors. Long regulatory periods increase the power of such incentives by allowing distributors to appropriate a material share of the savings that they achieve.
- Incentives to innovation and inter-sectorial synergies: a corollary of the previous two recommendations is that – in general – incentives for distributors to deploy innovative technologies should be mainly a by-product of regulatory schemes targeting outputs, rather than being pursued through schemes targeting specific technologies or solutions. This would ensure that only innovation directly impacting on the value of the service for network users' be implemented and, more generally, that regulation be technology neutral. The same recommendation holds for incentives to exploit synergies between distribution investments and the supply of non-energy local services; such incentives should be a by-product of regulatory schemes targeting total cost minimisation rather than of schemes targeting specific technologies or solutions;
- Re-openings and allowed revenue indexation: rare and unpredictable events beyond the distributors control may cause major departures from allowed revenues during the regulatory period[54]. Allowed revenue updates during the regulatory period (so called: re-openings) to account for such events are also desirable. However, such updates should be triggered only by very major events, whose occurrence and impact on cost are clearly beyond the distributor's control.

[54] These might include changes in the national or regional policy and regulatory framework.

Some major cost items beyond the distributors control are known to be variable in time. This might be the case, for example, for copper and steel prices. When robust indexes of such costs are available, the distributor's allowed revenues should be parametrized, in order to reduce the risk borne by distributors.

Notice that in both cases placing risk on distributors is of little or no use from an incentive perspective, since distributors don't have control on the events impacting on cost. On the other hand, the more risk is placed on distributors the higher is expected return necessary to attract capital in the industry and, therefore, the cost ultimately borne by consumers.

Sending correct price signals to consumers via distribution tariffs is consistent with the broad objective of developing demand flexibility pursued, by the Commission and by Member States. Our recommendations on distribution tariff structure are presented next.

Recommendation 4: efficient distribution tariffs should be designed to send long term incremental cost signals to consumers. In general, this requires that:

- Costs for consumer specific infrastructures be covered through standing charges or connection charges;
- Costs for shared infrastructures be split among network users based on each one's contribution to the infrastructure's peak load[55].

This recommendation is based on the conjecture that distribution capacity shortages are optimally addressed through network upgrades and that therefore scarcity conditions in distribution are typically transitory. If that condition holds, sending scarcity signals through distribution tariffs is not necessary.

If, instead, congestions turned out to be a permanent feature of optimally dimensioned distribution systems, dynamic pricing systems are far more effective in rationing available capacity than time-of-use tariffs set long before real time. We are not aware of any applications of dynamic charging to distribution services; therefore, any assessment of the relative merits of alternative models is speculative. However, experience in transmission pricing suggests that schemes addressing transportation capacity scarcity via locational energy price differentiation are more effective than schemes based on dynamic network charges.

[55] Large scale deployment of smart meters, capable of collecting high frequency withdrawal data will make it possible to assess each consumer's contribution to peak usage of distribution networks directly, while proxies are currently adopted in most countries.

Appendix 1: Country Reports

Country Report – Austria (electricity distribution)

2. Overview of the distribution sector

In Austria, the electricity distribution sector is rather fragmented with a relatively large (over 100) number of small DSOs, and few large federal state operators as well as some centered in the cities. The sector is fully regulated. The regulator has a peculiar structure, with an independent external Commission required to approve the main tariff related decisions. This Commission also acts as an appeals body with certain competences (no tariff related appeals).

2.1. Institutional structure and responsibilities

In Austria there are approx. 124 distributors supplying electricity to 5.87 million customers covering the whole country. Total distribution in 2013 amounted to ca. 62.5 TWh.

Detailed information about unbundling status is not available. The general requirement is that DSO over 100,000 customers are legally unbundled, but smaller ones may be also legally unbundled.

Smaller DSOs with less than 100,000 customers cover 8% of total demand.

Table 29: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 customers	Exemption *	Share of total demand
Country	124		11	113	NA	NA
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

The responsibility for setting the principle and the calculation methodology of distribution tariffs, as well as for approving their values, belongs to the regulatory authority (E-Control). The determination of tariffs involves a two-step procedure: at first, costs and volumes are approved by the board of directors of E-Control, providing the base for tariff determination. At second, the E-Control Commission is responsible for tariff determination (incl. tariff structure decisions). The E-Control Commission consists of different members of the National Chambers (representing interests of stakeholders, notably companies' and workers' interests). The E-Control Commission is appointed by the government based on the proposal of the federal minister of science, research and economy (§10 E-Control law). Decisions have to be taken by majority vote. The

Commission is responsible for tariff determination (including tariff structure) but is no longer (since 1.1.2014) the main appeals body for tariff related decisions regarding the tariff ordinance. Besides tariff setting, it is for example responsible for dispute settlement, standard terms and conditions for DSOs, etc.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 30: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO		Providing opinions	Providing opinions
Government	Issues principles	Issues principles	Issues principles
NRA (Board of Directors and E-Control Commission	Board of Directors: Cost and volume approval	E-Control Commission: approves tariffs sets principles for tariff structure	Principles set by law. Amount is determined by E-Control Commission.

(*) subject to E-Control Commission approval

The regulatory process adopted to set distribution tariffs involves the following steps:

1. E-Control Commission issues one consultation draft of the network tariff Ordinance.
2. Afterwards comments are discussed with the E-Control Commission.
3. Finally the Ordinance is published. Its effective date is (usually) always the 1st of January.

2.2. Key figures on revenue and tariffs

Distribution revenues in Austria in 2013 were approx. € 1,8 billion. Approx. ¾ of total revenues are related to distribution (system utility and network losses and other distribution related tasks) tariffs. Connection charges, system services and metering charges make share the rest equally.

A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

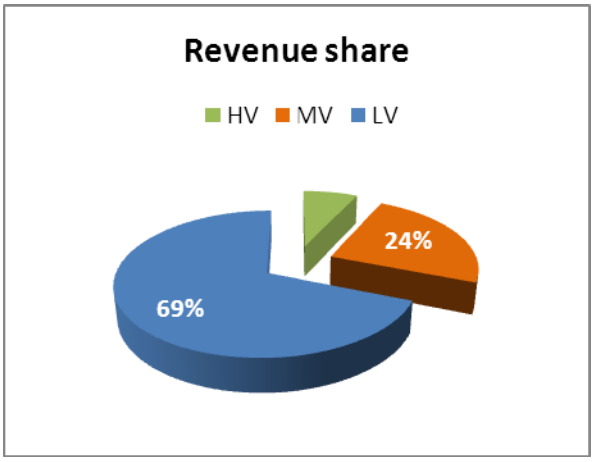
In Austria there are 7 voltage levels, but end users are mostly connected to 5 of them:

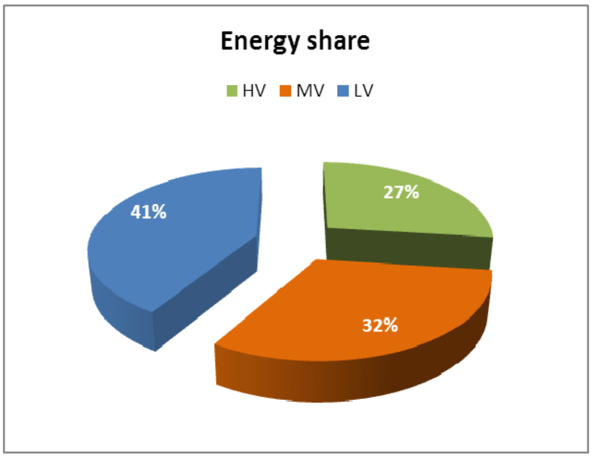
- Level 1: Ultra-high 380/220 kV (not applicable to distribution customers)
- Level 2: Transformation between UHV and HV
- Level 3: High 110 kV (typically large industrial customers belong here)
- Level 4: Transformation between HV and MV
- Level 5: Medium 35 kV (typically small industrial customers belong here)
- Level6: Transformation between HV and MV
- Level 7: Low 230/400 V (typically small businesses and households belong here)

Table 31: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenue
Level 3 & 4	kWh, kW	100	7%
Level 5 & 6	kWh, kW	150000	24%
Level 7	kWh, kW, fixed	5700000	69%

Figure 25: Proportion of revenue and energy accounted by voltage level





The typical customers for the main categories as well as their typical features are illustrated below:

Table 32: Typical customer types

Customer type	Service level	Notional Energy usage/y	Load
Residential	7	3500 kWh	Flat
Small business	7	210 MWh	75 kW
Small industrial	6	1140 MWh	300 kW
Small industrial	5	9000 MWh	2 MW
Large industrial	4	58 GWh	10 MW
Large industrial	3	195 GWh	30 MW

Distribution tariffs are segmented by voltage level, measurement, service type, time and geographical zone. There are four time brackets (winter and summer, both split in a peak and off-peak time) and 14 zones, amounting to the nine Austrian Provinces (incl. Vienna as state capital and province) plus special tariffs for the cities of Graz, Linz, Klagenfurt, Innsbruck and for Kleinwalsertal[56]. As a consequence there are more than 500 different tariff levels.

For the latest amendment of the System Utility Ordinance 2012 - amendment 2014 (Systemnutzungsentgelte-Verordnung 2012 – Novelle 2014; SNE-VO 2014) for voltage levels 3 - 5, there is a capacity charge comprised between approx. 12 and 39 €/kW, structured by zone; and an energy charge, structured by time and zone and comprised between 0,17 and 1,23 cents/kWh.

For voltage levels 6 and 7, the tariffs differ also by measurement and service type. The capacity charge is only applied for measured capacity (between 29 and 66 €/KW) and is added to an energy charge between 0,74 and 3,5 cents/kWh.

In case the capacity is not measured there is either an interruptible service (energy related) comprised between 1,5 and 4 cents/kwh; or (for Level 7 only, i.e. low voltage), a mix of a fixed (standing annual) charge (between 13,80 and 23,32 €/year, zone related) and an energy charge (between 3,137 and 5,69 cents/kWh, time and zone-related).

Moreover, there are 4 tariff times (summer and winter high and low) and there are major differences within the network areas. Thus this information only provides a broad range of variability and cannot be interpreted as any meaningful comparison between the zones.

The average tariffs per kWh are illustrated below.

[56] This is a small, isolated Tyrolean valley that is supplied through the German network and has therefore higher tariffs, it is excluded from the following analyses.

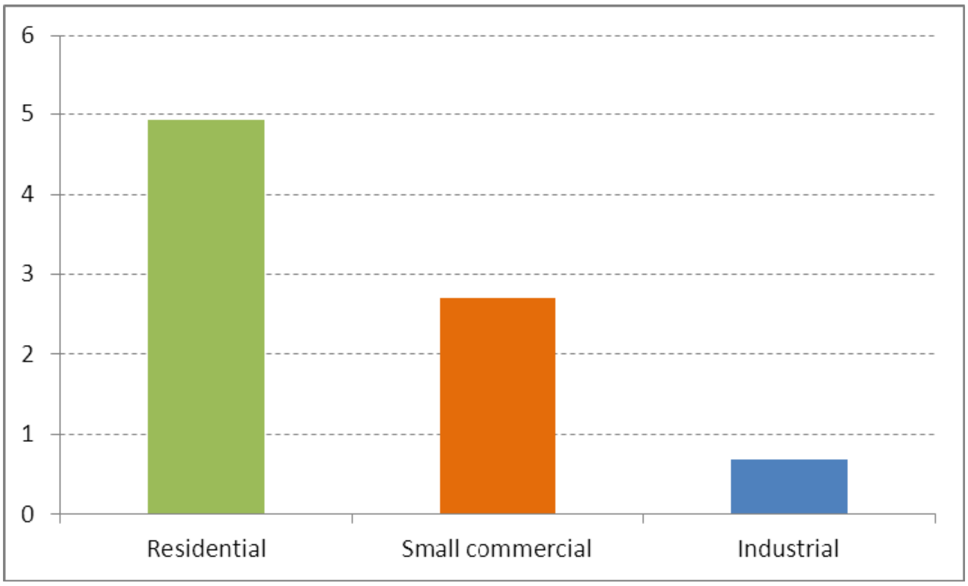
Table 33: Breakdown of annual charges – typical customer types, SNE-VO 2014 (€)

Customer type	Notional Energy usage	Fixed charges, €/year (*)	Energy charges, €c/kWh (*)	Load charges, €/kW/year (*)	Total (national average, €c/kWh)(+)
Residential grid level 7 not metered	3500kWh	17,28	3,88	0	4,93
Small commercial grid level 7 metered	50MWh		1,87	43,08	2,27
Industrial grid level 4	24000MWh		0,50	27,96	0,68

(*) Charges are segmented by time and geographical zone. Indicative values are provided for Vienna (industrial and commercial) and Lower Austria (residential), which are intermediate in the range.

(+) Data provided by E-Control

Figure 26: Average network charges (€c/kWh), 2013



3. Regulation of distribution activities

3.1. General overview

The role of the DSO in Austria is to provide and operate a distribution network able to cover the demand of the connected customers. Both CAPEX and OPEX are subject to regulation with benchmarking performed on TOTEX. The NRA (Board of Directors and Commission) sets the principles, issues the methodology and approves network tariffs (see two-step procedure described above). There are no formal end user price controls and the market is fully open. However, it is worth noticing that a large part of the supply industry is controlled by the state or local public sector, who may be subject to moral suasion by local government authorities.

The distribution tariff is itemized separately to end-users, within the same bill.

Key features of the regulatory regime are set out in the following table:

Table 34: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Competencies are delegated to Austria's provinces
Regulatory period (cost determination principles)	5 years
Validity of tariff ordinance	1 year
Form of determination (distributor propose/regulator decide)	Regulator decides
Scope for appeal regarding cost and volume determination	Federal administrative court
Scope for appeal regarding tariff ordinance	No appeal as such possible. However courts, the federal government and regional governments can initiate a constitutional review of the ordinance at the Constitutional Court. The Constitutional Court can then annul the ordinance.

3.2. Main incentive properties of the distribution regulatory model

Allowed (controllable) costs/revenues are subject to an RPI-X annual adjustment, where X is composed of a general (Xgen) and an individual component (Xind). Certain factors are used to take into account the expansion of services during the regulatory period New investments (CAPEX) are treated within a so-called "investment factor", a cost reimbursement approach based on realized book values based on a yearly audit procedure. There is no efficiency offset applied to new investments (undertaken during the regulatory period). In addition to the "investment factor", an "operating cost factor" accounts for changes in OPEX-levels during the regulatory period. The operating cost factor involves changes in network connections (no distinction between conventional and smart meters) and network length as relevant output parameters. Extra OPEX for Smart Metering which are not yet reflected in the operating cost factor are treated under a separate cost-plus system, subject to a yearly audit. Tariffs are calculated by the NRA based on regulated costs and are set by a yearly tariff ordinance. The individual X-factor is determined via benchmarking. A TOTEX benchmarking approach is applied, involving standardised CAPEX and using DEA and MOLS techniques. Xgen is determined via a TFP calculation (Thornquist Index).

The WACC structure involves a goal capital structure of 40% equity and 60% debt. If the actual equity ratio of a company is more than 10% below 40%, the actual equity rate will be used.

At the same time the following tools are provided to mitigate risks:

- Recalculation happens to avoid the t-2 problem in cost recognition;
- A regulatory account takes care of differences due to volume changes;
- DSOs might call for a rate revision on the basis of extraordinary events – these cases will be treated on a case by case basis and will be subject to an audit procedure.

There is no quality element in the tariff regulatory formula. However, various quality standards are defined and monitored (based on an Ordinance).

3.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 35: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Price-cap
Regulatory asset base	Tangible and non-tangible assets (no working capital), based on book values
Capital expenditure	(Controllable) CAPEX are subject to benchmarking, changes (basis is the audit year) during the regulatory period are reflected within a so-called “investment factor”.
Approach to operating expenditure	(Controllable) OPEX are subject to benchmarking, changes in service provision (connections, network length) with the audit year as reference, are reflected in a so-called “operating cost factor”
Form of WACC applied	Nominal, pre-tax
Additional revenue items (where applicable)	Non-controllable costs.

The following formula is applied in determining the WACC:

WACCpre-tax = D * (Rf + DP) + E * (Rf + eβ*RP) / (1-T)

Where:

- Risk-free rate (%) Rf
- Debt premium (%) DP
- Pre-tax cost of debt (%) CofD = Rf + DP
- Asset beta aβ
- Equity beta eβ = aβ*(E+D*(1-T))/E
- Risk premium (equity, market) (%) RP
- Pre-tax cost of equity (%) CofEpre = Rf + eβ*RP
- Post-tax cost of equity (%) CofEpost = CofEpre*(1-T)

- Equity (share) E
- Debt (share) D = 1 - E
- Pre-tax WACC, nominal (%) WACCpre = D * CofD + (E*CofEpost)/(1-T)

No further information is available. Criteria for the calculation of parameters are not published.

4. Tariffs for distribution services

4.1. Distribution tariffs

The *cascading approach* is adopted to allocate costs between customer categories with the following key features:

- Costs are cascaded from the upstream level, up to a maximum of 70%
- Secondary control and losses are not included
- Energy injected at the various voltage levels are considered in the calculation

The main services users pay for are:

- Network usage
- Network losses
- Metering
- For additional services

Large industrial customers pay a reduced tariff for the volume and load of electricity which is taken from the network in order to avoid destabilization.

Generators with a contracted power of more than 5 MW pay the tariff for network losses and system- service charges for system balancing costs.

Table 36: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Own tariffs for losses
Presence of uniform tariffs	For ultra-high voltage only
Presence of non-linear tariffs	Yes (degressive)
Presence of regulated retail tariffs	No
Presence of social tariffs	No

4.2. Connection charges

Connection charges include:

- a system admission charge, which reflects the costs for the preparation of the grid connection;
- a system provision charge, which reflects the costs of the power deployment of the DSO.

Table 37: Summary of key issues relating to connection charges

	Issue	Approach

Determination of charges	Type of charges (shallow/deep)	Deep
	Methodology adopted	Admission charge negotiated, provision charge regulated
Hosting capacity	Scope to refuse connection	Lack of capacity
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	No

5. Distribution system development and operation

System development is decided by DSOs, which must satisfy demand and are subject to capital cost monitoring and benchmarking. However the NRA does not approve their investment plans.

DSOs do not have the right to dispatch, excepts in special cases, but can influence the location of new generators.

5.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 38: Approach to distribution planning

Issue	Approach
Form of distribution planning document	DSO plans notified to NRA but not subject to approval
- Key responsibilities for its development	DSO
- Degree of integration with renewables plan	No specific relationship
- Relationship with consumption trends	No specific relationship
- Relationship with quality of service targets	No specific relationship
- How trade-offs between network development and alternative technologies are treated	No specific relationship
- Requirements to integrate cost benefit analysis	No specific relationship

5.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 39: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	Only in emergency
Possibility to dispatch flexible loads	Yes
Other sources of flexibility open to DSO	Demonstration projects only

The DSO has a role in the location of new generation plants, which it proposes with a view to minimise connections and network expansion.

5.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 40: Key approach to metering

Issue	Approach adopted
Discos role in metering	Own (normally, not by law) and operate the meters
Monopoly services in the metering	Yes
Smart metering functionality	(see below)

There were 237,085 smart meters installed by the end of 2013.

The plans for smart meter deployment are as follows:

- till 2015 10 %
- till 2017 70%
- 2019 95 % of all consumers (5.7 million)

The main features of the smart meters will be:

a) quarter-of an hour measurement,, but only in case the customers do agree to this
b) remote reading
c) remote disconnection/reconnection of customers
d) remote control of the maximum power that can be withdrawn
e) remote operation of appliances at the consumer's premises
f) local port to send real time consumption, but only in case the customers do agree to this information to a local screens or computers

These features and the deployment plan are required by an Ordinance of the Ministry for Economic Affairs.

There is no distinction between consumer categories.

Country Report – Austria (gas distribution)

1. Overview of the distribution sector

In Austria, the electricity distribution sector is rather fragmented with a relatively large (over 100) number of small DSOs, and few large federal state operators as well as some centered in the cities. The sector is fully regulated. The regulator has a peculiar structure, with an independent external Commission required to approve the main tariff related decisions. This Commission also acts as an appeals body with certain competences (no tariff related appeals).

1.1. Institutional structure and responsibilities

In Austria there are 20 distributors supplying electricity to 1,35 million customers covering about one third of the population, with a network of about 36000 Km. Total distribution in 2013 amounted to about 84 TWh.

Detailed information about unbundling status is not available. The general requirement is that DSO over 100000 customers are legally unbundled, but smaller ones may be also legally unbundled.

Smaller DSO with less than 100000 customers cover 8% of total demand.

Table 41: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 customers	Exemption*	Share of total demand
Country	20		9	14	NA	NA

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**

The responsibility for setting the principle and the calculation methodology of distribution tariffs, as well as for approving their values, belongs to the regulatory authority (E-Control). The determination of tariffs involves a two-step procedure: at first, costs and volumes are approved by the board of directors of E-Control, providing the base for tariff determination. At second, the E-Control Commission is responsible for tariff determination (incl. tariff structure decisions). The E-Control Commission consists of different members of the National Chambers (representing interests of stakeholders, representing companies' and workers' interests). The E-Control Commission is appointed by the government based on the proposal of the federal minister of science, research and economy (§10 E-Control law). Decisions have to be taken by majority vote. The Commission is responsible for tariff determination (including tariff structure) but is (no longer - since 1.1.2014) the main appeals body for tariff related decisions regarding the tariff ordinance. Besides tariff setting, it is for example responsible for dispute settlement, standard terms and conditions for DSOs, etc.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 42: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO		Providing opinions	Providing opinions
Government	Issues principles	Issues principles	Issues principles
NRA (Board of Directors and E-Control Commission	Board of Directors: Cost and volume approval	E-Control Commission: approves tariffs sets principles for tariff structure	Principles set by law. Amount is determined by E-Control Commission.

(*) subject to E-Control Commission approval

The regulatory process adopted to set distribution tariffs involves the following steps:

4. E-Control Commission issues one consultation draft of the network tariff Ordinance.
5. Afterwards comments are discussed with the E-Control Commission.
6. Finally the Ordinance is published. Its effective date is (usually) always the 1st of January.

1.2. Key figures on revenue and tariffs

Distribution revenues in Austria in 2013 were € 541,5 million.

A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

In Austria there are 3 network levels, of which 2 belong to distribution:

- Level 2: Pressure delivery over 6 bar
- Level 3 Pressure delivery under 6 bar

Table 43: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenue
Level 2	KWh, KWh/h	352	85,1 MM€
Level 3	KWh, KWh/h	1348660	456,5 MM€
Total		1349012	541,5 MM€

There are four system tariff components, but in fact only the system utilisation charge (*Systemnutzungsentgelt*), covers cost of constructing, expanding, maintaining and operating the system, including the costs arising in connection with installing and operating meters as well as their calibration and meter reading at injection and withdrawal points, except at customer facilities.

Other tariff components are related to connections and metering and are therefore discussed in the next sections.

System utilization charges are segmented by network (delivery pressure) level, measurement, consumption level and geographical zone. Since there are 2 network levels, 2 measurement types (for level 3 only: with or without hourly peak measure), 9 geographical zones (the 9 Austrian Provinces or Länder) and 10 consumption blocks, there are more than 300 values.

The *cascading approach* is adopted to allocate costs between customer categories with the following key features. Costs are cascaded from the transmission level (Level 1), up to a maximum of 70%, and from level 2 to level 3 within distribution.

BY NRA's decision, costs are allocated for 70% to the capacity or fixed sub-components and for 30% to the energy related sub-components.

Commodity related charges are differentiated by province and consumption block, whereas fixed and capacity related charges only by province. Smaller customers pay a fixed charge rather than a capacity related one. Large customers (with peak over 400,000 kWh/h), connected to level 2, can also opt for a different combination, featuring higher energy-related and lower capacity related sub-components. This is particularly useful for a flexible use of peak-shaving power stations.

A discount of the capacity charge applies to industries consuming between March and October only.

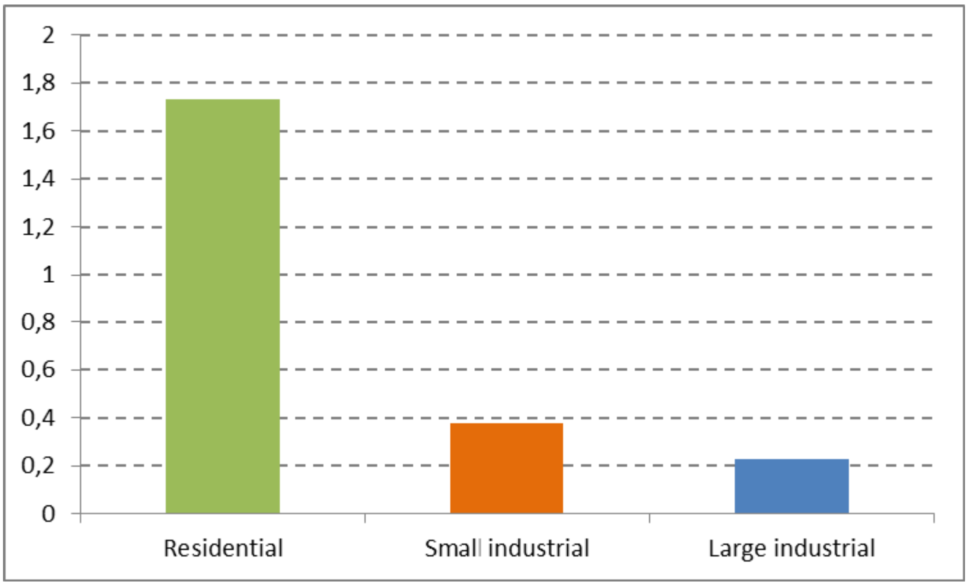
Tariffs by connection levels and consumption block are shown in the Table below. Ranges are shown for subcomponents that are differentiated by province.

Table 44: Breakdown of annual charges – typical customer types (network area lower Austria), 2013 (€)

Zone	Consumption block (kWh/year)	Network level	Energy related charge range (€c/kWh)	Capacity related charge range (€/kWh/h/year)	Fixed Charge (€/year)
A	0 – 5000	2	0,06	2,7 – 5,4	-
B	5001 – 10000	2	0,06	2,7 – 5,4	-
C	10001 – 100000	2	0,06	2,7 – 5,4	-
D	100000001 – 200000000	2	0,05	2,7 – 5,4	-
E	200000001 – 900000000	2	0,05	2,7 – 5,4	-
F	From 900000001	2	0,05	2,7 – 5,4	-
1	0	3	1,6	-	30

Zone	Consumption block (kWh/year)	Network level	Energy related charge range (€c/kWh)	Capacity related charge range (€/kWh/h/year)	Fixed Charge (€/year)
2	40	3	1,0	-	30
3	80	3	0,9	-	30
4	200	3	0,9	-	30
A	0 – 5000	3	0,37	4,5	-
B	5001 – 10000	3	0,16	4,5	-
C	10001 – 100000	3	0,03	4,5	-
D	From 100000001	3	0,03	4,5	-

Figure 27: Average network charges (€c/kWh), 2013



2. Regulation of distribution activities

2.1. General overview

The role of the DSO in Austria is to provide and operate a distribution network able to cover the demand of the connected customers. Both CAPEX and OPEX are subject to regulation with benchmarking performed on TOTEX. The NRA (Board of Directors and Commission) sets the principles, issues the methodology and approves network tariffs (see two-step procedure described above).

There are no formal end user price controls and the market is fully open. The distribution tariff is itemized separately to end-users, within the same bill.

Key features of the regulatory regime are set out in the following table

Table 45: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Competencies are delegated to Austria's provinces
Regulatory period (cost determination principles)	5 years
Validity of tariff ordinance	1 year
Form of determination (distributor propose/regulator decide)	Regulator decides
Scope for appeal regarding cost and volume determination	Federal administrative court

2.2. Main incentive properties of the distribution regulatory model

Allowed (controllable) costs/revenues are subject to an RPI-X annual adjustment, where X is composed of a general (Xgen) and an individual component (Xind). Certain factors are used to take into account the expansion of services during the regulatory period. New investments (CAPEX) are treated within a so-called "investment factor" and an "operating cost factor" accounts for changes in OPEX-levels during the regulatory period. Tariffs are calculated by the NRA based on regulated costs and are set by a yearly tariff ordinance.

The individual X-factor is determined via benchmarking. A TOTEX benchmarking approach is applied, involving standardised CAPEX and using DEA and MOLS techniques. Xgen is determined via a TFP calculation (Thornquist Index).

The WACC structure involves a goal capital structure of 40% equity and 60% debt. If the actual equity ratio of a company is more than 10% below 40%, the actual equity rate will be used

At the same time the following tools are provided to mitigate risks:

- Recalculation happens to avoid the t-2 problem in cost recognition;
- Recurring recalculation of "planned" and "actual" expansion factors reflecting OPEX and CAPEX divergences. The system works similarly to the mechanism of the regulatory account;
- DSOs might call for a rate revision on the basis of extraordinary events – these cases will be treated on a case by case basis and will be subject to an audit procedure

There is a quality element in the tariff regulatory formula, but it is currently set to zero. However, various quality standards are defined and monitored (based on an ordenance).

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 46: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Price-cap
Regulatory asset base	Tangible and non-tangible assets (no working capital), based on book values
Capital expenditure	(Controllable) CAPEX are subject to benchmarking, changes (basis is the audit year) during the regulatory period are reflected within a so-called “investment factor”.
Approach to operating expenditure	(Controllable) OPEX are subject to benchmarking, changes in service provision (metering points, network length) with the audit year as reference, are reflected in a so-called “operating cost factor”
Form of WACC applied	Nominal, pre-tax
Additional revenue items (where applicable)	Costs of smart metering, non-controllable costs.

The following formula is applied in determining the WACC:

WACCpre-tax = D * (Rf + DP) + E * (Rf + eβ*RP) / (1-T)

Where:

- Risk-free rate (%) Rf
- Debt premium (%) DP
- Pre-tax cost of debt (%) CofD = Rf + DP
- Asset beta aβ
- Equity beta eβ = aβ*(E+D*(1-T))/E
- Risk premium (equity, market) (%) RP
- Pre-tax cost of equity (%) CofEpre = Rf + eβ*RP
- Post-tax cost of equity (%) CofEpost = CofEpre*(1-T)
- Equity (share) E
- Debt (share) D = 1 - E
- Pre-tax WACC, nominal (%) WACCpre = D * CofD + (E*CofEpost)/(1-T)

No further information is provided. Criteria for the calculation of parameters are not published.

3. Tariffs for distribution services

3.1. Distribution tariffs

Table 47: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Own tariffs for losses
Presence of uniform tariffs	For ultra-high voltage only
Presence of non-linear tariffs	Yes (degressive)
Presence of regulated retail tariffs	No
Presence of social tariffs	No

3.2. Connection charges

Connection charges include:

- System admission charge, covering costs of direct connection, set by the DSOs. Thy are uniform for small customers.
- System provision charge covering further network reinforcement costs that may be necessary for connection. Currently set by the regulator at 3 €/kWh/h.

Table 48: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Deep
	Methodology adopted	Admission charge negotiated, provision charge regulated
Hosting capacity	Scope to refuse connection	Only if capacity inadequate or connection of new customer not cost-efficient
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	No

4. Distribution system development and operation

System development is decided by DSOs, which must satisfy demand and are subject to capital cost monitoring and benchmarking. However the NRA does not approve their investment plans.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 49: Approach to distribution planning

Issue	Approach
Form of distribution planning document	No DSO development plans are foreseen. Entry capacities requirements implicit in transmission development plans.
Key responsibilities for its development	DSO
Degree of integration with renewables plan	No specific relationship
Relationship with consumption trends	No specific relationship
Relationship with quality of service targets	No specific relationship
How trade-offs between network development and alternative technologies are treated	No specific relationship
Requirements to integrate cost benefit analysis	No specific relationship

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 50: Key approach to metering

Issue	Approach adopted
Discos role in metering	Own (normally, not by law) and operate the meters
Monopoly services in the metering	Yes
Smart metering functionality	(see below)
Non hourly metered consumption	Published load profiles by DSO

The share of non-hourly metered consumption is 41%.
Only some smart gas meters are installed in Austria. There are no plans for smart meter deployment.

Country Report – Cyprus (electricity distribution)

1. Overview of to the distribution sector

There is only one DSO operating in Cyprus, and it is part of the country´s vertically-integrated utility.

The NRA is responsible for approving the allowed tariffs (revenues) of the DSO, as well as the tariff structures and connection costs. The DSO develops proposals for each of these components, for the NRA.

1.1. Institutional structure and responsibilities

In Cyprus there is 1 distributor supplying electricity to 549448 customers. Summary data on industry structure is set out below.

Table 51: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	1	N.a.	N.a.	0	Yes, embedded generators do not pay any distribution tariffs	N.a.

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**

The DSO is owned by the EAC, which is a vertically-integrated utility and includes the largest retail company.

The responsibility for setting distribution tariffs is spread between the following jurisdictions (for example):

- The DSO calculates the allowed revenue
- The NRA issues a methodology; and approves or not the DSO´s calculated proposal of allowed revenue
- Government issues the principles in primary law

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 52: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Calculates the allowed revenue	Prepare a tariff proposal and submit it to the NRA for their approval	Calculates for NRA approval
Government	Defines main principles in primary law	Not involved	Not involved
NRA	Sets the tariff calculation methodology, and approves (or not) the DSO´s proposed allowed revenues	Prepares the tariff methodology (issued as a regulation)	Approves (or not) the DSO´s proposal

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process used for setting distribution tariff structures is that the NRA prepares the tariff methodology, which is issued as a regulation. The DSO, in collaboration with other departments of the incumbent (EAC), prepare a tariff proposal which is submitted to the NRA for their approval.

A consultation process is used within tariff decisions. Specifically, the NRA issues one consultation paper and held public hearings.

1.2. Key figures on revenue and tariffs

Distribution revenues in Cyprus in 2013 were € 91,96 million. A breakdown of this total amount between different distribution activities is not available at the current time. In fact, the NRA is currently in the process of unbundling the accounts of the vertically-integrated company and of implementing a revised Electricity Tariffs Methodology.

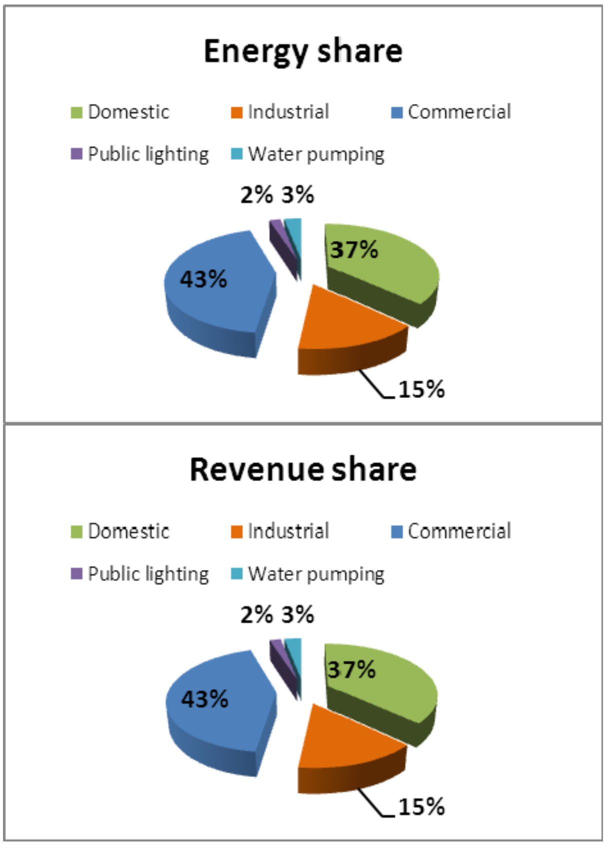
A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 53: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenues
Domestic	KWh, fixed charge	428616	33,9 million
Industrial	KWh, fixed charge	10222	13,7 million
Commercial	KWh, fixed charge	84695	39,2 million
Public lighting	KWh, fixed charge	10365	2,1 million
Water pumping	KWh, fixed charge	15280	3,0 million
Total	-	549448	91,96 million

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 28: Proportion of energy and revenue accounted by customer categories



As can be seen from the figures above, according to the NRA the allowed revenues of each customer category in 2013 exactly matched the energy consumption shares of each category.

Customer categories are defined as follows:

- Domestic – where the electricity is solely used for domestic purposes to private dwellings;
- Commercial – where the electricity is solely used for commercial purposes or for any other purposes related to commerce or profession;
- Industrial – where the electricity is for the purpose of electromotive power or electromechanical or electro-thermal processes in factories, workshops, foundries, mills, pumping stations or other industrial installations;
- Public lighting – where the electricity is supplied for the purpose of public lighting or other purposes approved by EAC and it is offered to Municipalities or Local Authorities or other Public Organisations;
- Water Pumping – where the electricity is solely used for water-pumping, for the purpose of water supply and/or irrigation and/or drainage of rain water, with restricted hours of supply.

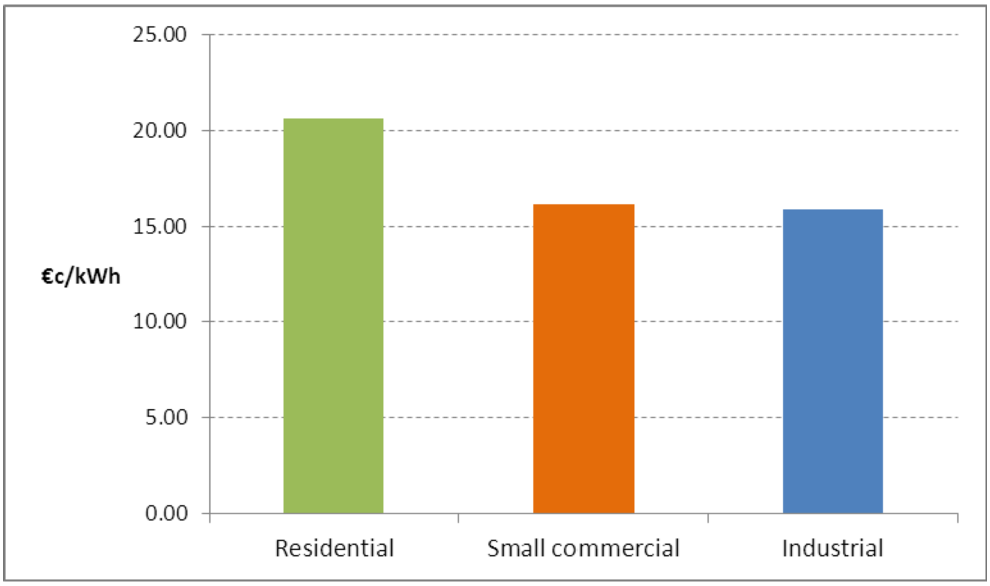
The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below:

Table 54: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Demand and reactive charges	Total
Residential	3500kWh	177	545	-	722
Small commercial	50MWh	126	7980	-	8106
Industrial	24000MWh	120	3768000	-	3815049

The resulting average tariffs per kWh are illustrated below.

Figure 29: Average network charges (€cents/kWh), 2013



2. Regulation of distribution activities

A cost-plus approach is used to determining allowed revenues, wherein the DSO proposes and the NRA makes a final decision of approval.

Reasonably-incurred costs are rolled into the Regulatory Asset Base. A WACC is not used.

2.1. General overview

The distribution sector is regulated under cost-plus regulatory regime. This regime does not use incentives and no risk mitigation measures are used.

Key features of the regulatory regime are set out in the following table:

Table 55: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	N.a.
Duration of tariff setting regime	N.a.
Form of determination (distributor propose/regulator decide)	DSO proposes and the NRA approves (or not) the proposal
Scope for appeal regulatory decision	N.a.

2.2. Main incentive properties of the distribution regulatory model

No regulatory incentives are applied for the DSO. There is no specific quality of service regulation in place either.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 56: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Cost-plus, without performance incentives
Regulatory asset base	Reasonably-incurred costs are included in the RAB (based on actual costs). No benchmarking of costs.
Capital expenditure	Historic costs, no benchmarking, no ex ante approval of CAPEX investments
Approach to operating expenditure	Cost-plus on incurred OPEX costs
Form of WACC applied	No WACC is applied. A fixed 6% rate is used
Additional revenue items (where applicable)	N.a.

The regulatory period for setting tariffs is 5 years. At the end of each year an ex post assessment is performed and distributions tariffs are revised if necessary. Investments of the DSO are not required to obtain ex ante approval from the NRA.

In assessing the DSO´s investment requirements, the NRA checks the reasonableness of the investment requirements and approves accordingly.

The regulator is allowed to include, in the DSO´s RAB, the investments that are determined to be necessary for the operation of the business. If any investments are considered to be unnecessary they may be excluded. However, this has not happened before.

3. Tariffs for distribution services

All customer groups pay a charge on energy which is effectively uniform, and tariffs are linear.

Retail tariffs are regulated for all customers, and there are no social tariffs in effect.

3.1. Distribution tariffs

In the process of allocating distribution costs to tariffs, the total distribution cost is allocated on the basis of the estimated (future) amount of kWh sold. All customers pay the same amount on each kWh consumed. Therefore, there is a fixed charge on energy.

Tariff components are not further split into sub-components, corresponding to the different activities carried out by the DSO.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 57: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Not charged as part of the distribution tariffs
Presence of uniform tariffs	Yes
Presence of non-linear tariffs	No
Presence of regulated retail tariffs	Yes, retail tariffs are regulated for all customers
Presence of social tariffs	No

There are no further components included in the distribution tariffs that do not correspond to distribution costs.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 58: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	In general, connection charges are shallow in nature. In some exceptional cases, charges are deep.
	Methodology adopted	The connection charges used, and which are approved by the NRA, include: standard costs for distribution equipment and labour, as well as generalised cases based on simulations.
Hosting capacity	Scope to refuse connection	It must always provide a connection proposal for all consumers and generators
	Requirements to publish hosting capacity	It is not obliged to publish all the details of the available capacity in its network; however, it must provide such information in the event that the NRA requests it.
	Targets and/or incentive schemes to enhance hosting capacity	None, the DSO is assumed to have a duty to connect all the capacity requiring a connection (and therefore it is assumed that the DSO will naturally implement the necessary measures to ensure that).

There is no specific regulation in force that does not hamper investment which implies additional OPEX (such as smart grid technology, use of demand side flexibility for grid services, or voltage regulation by decentralised resources, etc.). However, any large scale implementation of specific plans, e.g. smart grids, requires their cost viability to be proven through relevant studies.

4. Distribution system development and operation

The DSO considers long-term electricity distribution sector development for certain regions of the country (in an informal approach), which takes into consideration likely RES development, and the evolution of consumption.

The DSO is responsible for metering services provision; a pilot study is being undertaken on smart meters in Cyprus, focusing mainly on net metering of small-scale PV power generation.

In 2013 there was no significant level of smart meter installment in the country. The roll out of smart meters may take place in the future, and the roll out strategy will likely be informed by the results of pilot studies and trials.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 59: Approach to distribution planning

Issue	Approach
Form of distribution planning document	There is no specific distribution planning document, but the DSO carries out long-term development studies for specific geographic areas (i.e. cities).
- Key responsibilities for its development	N.a.
- Degree of integration with renewables plan	In general terms, plans for future RES connections are taken into consideration when they are quantified and known.
- Relationship with consumption trends	The likely evolution of consumption is taken into full consideration in the DSOs long-term analyses (not planning documents).
- Relationship with quality of service targets	Quality of service factors (however, not targets) are taken into consideration by the DSO in planning. Particularly, aspects related to reinforcement are considered, that is, improving voltage conditions or security of supply aspects.
- How trade-offs between network development and alternative technologies are treated	No specific treatment in place at the present time.
- Requirements to integrate cost benefit analysis	The DSO takes into consideration CBA, but the results are not required to be published.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 60: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	DSOs do not have any scope to dispatch embedded RES generators. This requirement falls on the TSO for RES generators above a certain production level
Possibility to dispatch flexible loads	No possibility for dispatching flexible loads at the present time
Other sources of flexibility open to DSO	A small pilot project being developed for introducing batteries. The study is being led by the distribution system owner.

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 61: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSO is responsible for metering; the meters are owned by the network owner
Monopoly services in the metering	Yes, the (one) DSO active in Cyprus is a monopolist in metering services
Smart metering functionality	A pilot study on the use of smart meters in Cyprus is being undertaken, on around 3.000 customers. The exact details of the smart meters being tested are unconfirmed, but it is known that net-metering of small-scale RES generation is a key feature of the technology.

In 2013 there was no substantial level of smart meter instalments in the electricity distribution sector. However, a pilot study was underway. The study was part of a 3-country analysis (Cyprus, Slovenia and Portugal) and was mainly focused on analysing metering technologies for small-scale solar PV generators feeding power into the distribution system.

The project, "Promotion of PV energy through net metering optimization" (PV-NET), aims to develop better energy policy for the promotion of renewable energies in the Mediterranean countries, targeting the best and most cost efficient use of PV technology.

The approach used made use of an optimization tool to help design a best-practice net-metering policy of the region based on various factors. Some factors include the environmental profile and the electricity consumption patterns of consumers in the investigated region.

The pilot sites are divided into two parts. The first concerns weather stations, where the POA irradiance, ambient and module temperature are measured. The other part is the smart meter solution, where smart-meters are installed in domestic or public buildings which own a PV electricity generation system, and measures the electricity consumed and produced. Data are gathered remotely every 15 minutes; the data is stored, monitored and analyzed. The data is viewable and downloadable online.

The study will later draw conclusions on the efficacy of such technologies, before developing its tentative advice for the region in terms of the practicability and best approach for promoting such smart meter applications in Cyprus (and the broader Mediterranean region).

Country Report – Czech Republic (electricity distribution)

1. Overview of to the distribution sector

In the Czech Republic operates 3 legally unbundled DSO and some other small DSO with less than 90000 customers that are not unbundling obligations in place. The main responsible of regulation and tariff setting is the NRA.

1.1. Institutional structure and responsibilities

In the Czech Republic there are 3 large distribution system operators, each DSO has a specific area of service and none of them operates in the whole country. Additionally there are some others small local regional DSO´s.

Total distributed amount of energy in 2013 was 52,3 TWh to 5863 million of customers.

The DSO´s in the Czech Republic have legal unbundling in accordance with the rules of unbundling laid down in the Article 26 of Directive 2009/72/EC. However for the DSO´s with less than 90000 connected customers there are no unbundling obligations in place.

Table 62: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 90000 customers	Exemption*	Share of total demand**
Country	308	0	3	305	N/A	16,81%

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**
**** Share of total demand expresses share of total consumption of energy inside areas of distribution networks with less than 90,000 connected customers to total consumption of energy in the Czech republic.**
In The Czech Republic, DSO´s cover all demand because there are not customers connected directly to the transmission network.

According to Energy Act 458/2000 COLL, the responsibility of regulation the prices for the transmission and distribution of electricity and for system services, as well as electricity prices for the supplier of last resort shall be regulated by the Energy Regulatory Office (ERO) hereinafter The NRA.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 63: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO			
Government			
NRA	X	X	X

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

1.2. Key figures on revenue and tariffs

Distribution revenues in 2013 were € 1179 million, broken down by the following activities:

- Depreciation – 361,953 € million (30,7%)
- Profits –301,824 € million (25,6%)
- Allowed cost – 515,223 € million (43,7%)

The allowed cost can be divided to:

- Operation and management of the distribution system – 166,932 € million (32,4%)
- Repairs and maintenance– 165,387 € million (32,1%)
- Metering – 83,466 € million (16,2%)
- Customer management– 49,977 € million (9,7%)
- Strategy and planning of development and renovation of distribution system – 49,491 € million (9,6%)

Distribution tariff are defined by voltage levels:

- High Voltage
- Medium Voltage
- Low Voltage. Consumer categories in LV are divided in LV residential (D) and other LV consumer (C). Consumer categories on LV are further divided according to main use of electricity consumed (C01d, C02d, … C62d for LV and D01d, D02d, … D61d for LV residential)

Each tariff has the following components:

- Monthly Capacity charge: based on the rated current of contractual capacity for HV and MV, and the main circuit breaker upstream of the electricity meter for LV. (CZK/MW/month for HV and MV customers and CZK/A/month for LV customers)
- Distributed Energy charge: based of the quantity of energy distributed. (CZK/ MWh).

A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 64: Tariff components, customers and revenues per customer class

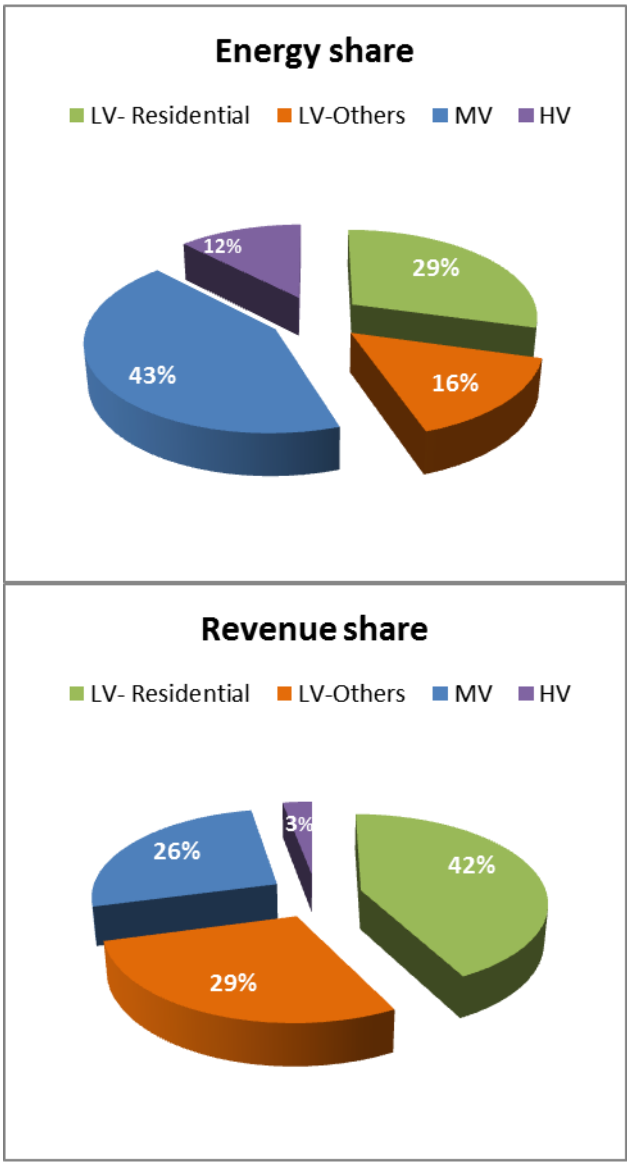
Customer classes	Tariff components	N. of customers	Revenue (€ million)
High Voltage	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	127	50,395
Medium Voltage	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	25433	446,800
Low Voltage Others- C01d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	259799	485,585
Low Voltage Others- C02d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	267218	
Low Voltage Others- C03d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	15299	
Low Voltage Others- C25d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	119874	
Low Voltage Others- C26d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	8846	
Low Voltage Others- C27d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	0	
Low Voltage Others- C35d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	1830	
Low Voltage Others- C45d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	53304	
Low Voltage Others- C55d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	434	
Low Voltage Others- C56d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	1433	
Low Voltage Others- C62d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	36047	
Low Voltage Residential D01d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	689587	721,782
Low Voltage Residential - D02d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	2753015	
Low Voltage Residential - D25d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	1076816	
Low Voltage Residential - D26d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	72870	
Low Voltage Residential - D27d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	3	
Low Voltage Residential - D35d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	12675	
Low Voltage Residential - D45d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	420344	
Low Voltage Residential - D55d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	5997	
Low Voltage Residential - D56d	Capacity charge (CZK/MW.month) , Distributed Energy (CZK/ MWh)	35385	
Low Voltage Residential - D61d	Capacity charge (CZK/MW.month), Distributed Energy (CZK/ MWh)	7146	
Total	-	5863482	1704,562

Currency rate used CZK/EUR: 27,82 (21. August 2014). Revenues showed by consumer class include TSO revenues.

Above revenue data for consumer class is from DSO with more of 90000 customers (3 DSO´s) in 2013. This revenue includes allowed revenues of DSOs, TSO (which is in effect a pass-through cost within DSOs' allowed revenue) and allowed cost of losses in systems. These revenues were paid by costumers in price for reserved capacity and price for distributed energy

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 30: Proportion of energy and revenue accounted by customer categories



The figure above shows that the households (LV- Residential) pay on average less than small commercial users (LV-Others).

The typical network tariff in 2013 for LV-Residential, LV- Others and industrial customers is illustrated below:

Table 65.1: Breakdown of annual charges – typical customer types, 2013 (Kč, prices without VAT)

Customer type	Tariff	Average Energy usage	Fixed charge (Average of DSO prices)	Capacity charge (Average of DSO prices)	Distributed Energy charge	Total
LV residential	Tariff D 02d; circuit breaker over 3x20A up to 3x25A, inclusive	2300 kWh	959	x	4185	5144
LV other	Tariff C 02d; circuit breaker over 3x20A up to 3x25A, inclusive	4123 kWh	1333	x	9515	10848
Industrial consumer, connected to MV. (Average contractual capacity per consumer is 0.22 MW).		870 MWh	x	409035	69664	478699

Data provided by national regulator according to the average energy usage in the country.

For ease of comparison, the Table is also reported in Euros.

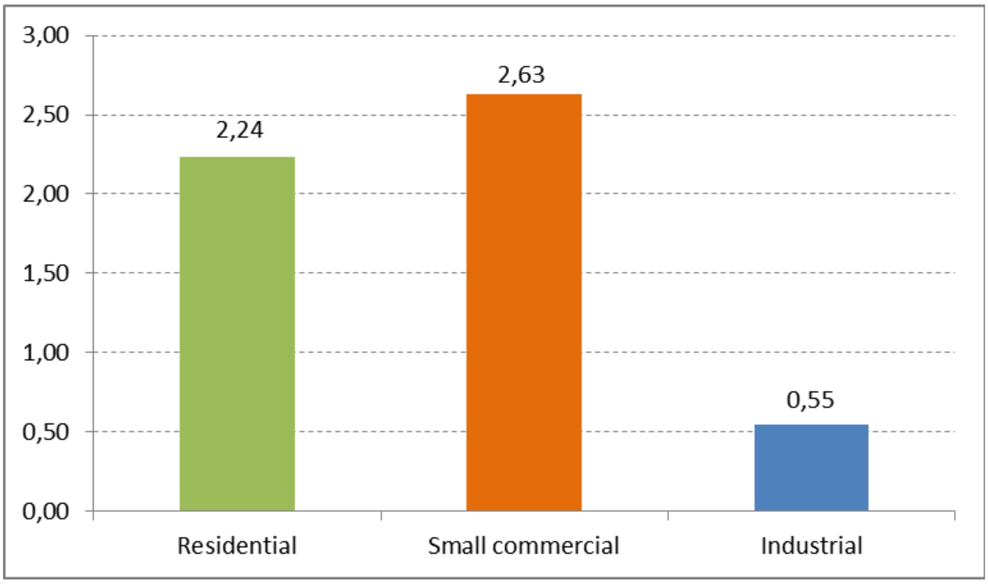
Table 65.2: Breakdown of annual charges – typical customer types, 2013 (€, prices without VAT)

Customer type	Tariff	Average Energy usage	Fixed charge (Average of DSO prices)	Capacity charge (Average of DSO prices)	Distributed Energy charge	Total
LV residential	Tariff D 02d; circuit breaker over 3x20A up to 3x25A, inclusive	2300 kWh	36,92	x	161,11	198,03
LV other	Tariff C 02d; circuit breaker over 3x20A up to 3x25A, inclusive	4123 kWh	51,32	x	366,30	417,61
Industrial consumer, connected to MV. (Average contractual capacity per consumer is 0.22 MW).		870 MWh	x	15476,47	2681,83	18428,30

1€ = 25.9763 CZK (Average 2013)

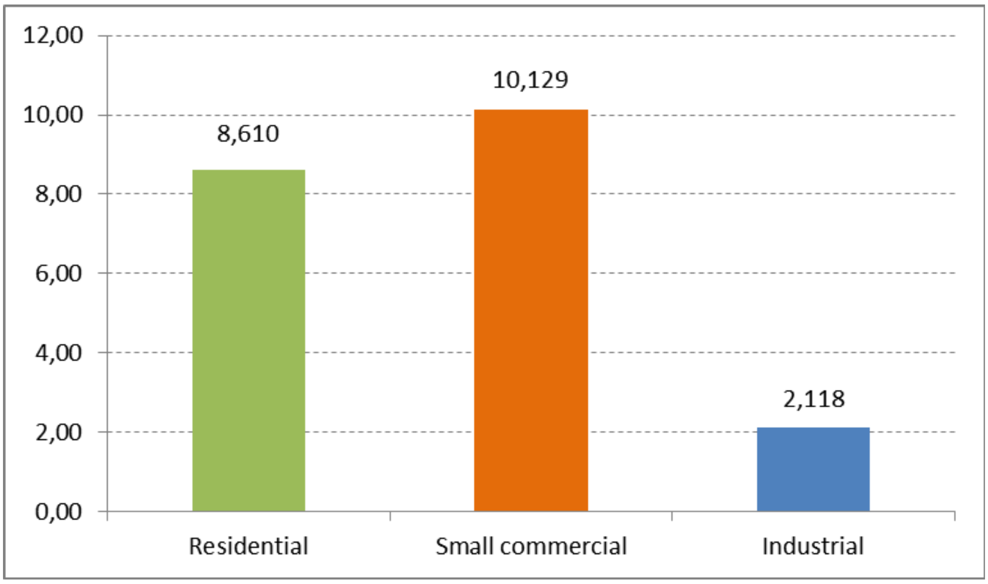
The resulting average tariffs per kWh are illustrated below.

Figure 31.1: Average network charges (Kč/kWh), 2013



For ease of comparison, the figure is also reported in cent of Euros.

Figure 31.2: Average network charges (€ Cent /kWh), 2013



2. Regulation of distribution activities

The distribution sector is regulated under a mix of cost reimbursement and incentive based model. DSO operates in a licence regimen. Licences are not allocated through competition; every DSO who meets the requirements will get the licence The model ensures to DSO achieve the allowed revenues. The regulatory system does not place volume risk or market conditions risks on the DSO.

2.1. General overview

The Act 458/2000 COLL provides the main rules of the whole Energy Sector, including electricity distribution. The Act establishes that to develop business activities in the energy sector as distribution activities a government authorisation in the form of a licence granted by the Energy Regulatory Office is required.

According to section 25, the DSO´s shall: "Provide reliable operation and development of the distribution system in the territory delineated by the licence; Enable electricity distribution on the basis of concluded contracts; and Control the electricity flows within the distribution system while respecting electricity transmissions between other distribution systems and the transmission system, doing so in co-operation with operators of other distribution systems and the transmission system operator".

The NRA (Energy Regulatory Office- ERO) is the administrative authority to regulate the energy sector. "The mission of the Energy Regulatory Office is to support economic competition, to support the use of renewable and secondary energy sources, and to protect consumers' interests in those areas of the energy sector where competition is impossible, with the aim to meet all reasonable requirements for the supply of energy".

The distribution activities are regulated under a licence regime. The DSO licence is for a maximum of 25 years period. The NRA should revoke a licence to the holder in some cases, detailed in Section 10 of the Energy Act.

The broad regulatory model implement in the Czech Republic is a mix of "cost reimbursement" and "incentive based". Capital costs are subject to "cost reimbursement", while operating cost are subject to a "revenue cap" system.

Key features of the regulatory regime are set out in the following table

Table 65: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Licence. Maximum 25 years period
Duration of tariff setting regime	Regulatory period is set for 5 years. However the tariffs are setting annually.
Form of determination (distributor propose/regulator decide)	Regulator decides
Scope for appeal regulatory decision	No

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Revenue CAP for operating costs of DSO
- Losses. A percentage of losses are fixed for whole regulatory period. If DSO is able to decrease the percentage of losses within the regulatory period, it will be allowed to obtain additional revenues. If the percentage of losses within the regulatory period increases, DSO will bear additional costs.
- Quality of service. If DSO achieves better parameters of SAIFI and SAIDI, it will receive additional revenues and vice versa.
- Unauthorized consumption - DSO is allowed to receive additional revenue from detected unauthorised consumption
- The allowed revenue is balanced with a two-year lag. There is an ex-post regulatory account (called correction factor) for allowed revenues; the difference between actual and allowed revenue is settled two years later (year+2)

At the same time the following tools are provided to mitigate risks:

- The regulatory framework may be altered during the regulatory period in case the electricity market conditions or general economic situation change significantly compared to the original situation.
- The cost base for each subsequent regulatory period is set based on actual costs incurred in a certain period of the previous regulatory period.
- If DSO is able to decrease the percentage of losses within the regulatory period, it will be allowed to obtain additional revenues. After the end of the regulatory period, the allowed percentage of losses will decrease and consumers will gain from lower cost for losses.
- Regulatory system does not place volume risk on the DSO. Tariffs are adjusted year to year through a regulatory account.
- Regulatory framework evaluates risk for infrastructure projects as a systematic risk for DSO using capital asset pricing model. Risk of cost overrun is partly mitigated (CAPEX is cost-plus)

Quality service is monitored since 2008 (in the required structure). Since 2013 an incentive mechanism (based on bonus and penalty) for quality of supply has been introduced into the regulation. Allowed revenues are increased (decreased) if he DSO performs better (worse) than predefined quality targets.

There are several guaranteed standards (technical and commercial) that should be met. If not, a consumer can claim compensation. The compensation is not automatic. Consumer must apply for compensation.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 66: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Capital costs are subject to "cost reimbursement", while operating cost are subject to a "revenue cap" system.
Regulatory asset base	Before this regulatory period, there was revaluation of assets because of unbundling. The current RAB is based on this revaluated (based on replacement values) book value of assets and is not further indexed
Capital expenditure	There is no approval process of investment in the regulation. There is no methodology implemented by the regulator to assess the DSO investment requirements
Approach to operating expenditure	OPEX of regulated subjects is compared only in special cases. There are not different costs assessment for some activities or special projects
Form of WACC applied	Nominal, pre-tax WACC
Additional revenue items (where applicable)	Not applicable

The following formula is applied in determining the real-pre-tax WACC:

$$WACC = \frac{R_E}{1-T} \cdot \frac{E}{D+E} + R_D \frac{D}{D+E} \cdot$$

Where:

- $R_{E:}$ is the real price of equity and own funds calculated according to the formula:

$$R_E = R_F + \beta_L \times ERP$$

- $R_{D:}$ is the cost of debt. The regulator calculated the value for the year 2014 (3.78%).
- R_F is profitability of an risk-free asset, calculated average revenue from 10+ year government bonds issued in between May 2012 and April 2013 for the year 2014 at 2.3%,
- The NRA set ERP as the sum of the basis ERP and the Czech Republic´s risk premium. In the years of III. regulatory period the Czech Republic´s risk premium has been set on the basis of the published data on the basis points of default spread from Professor Damodaran's database and in relation to the then current rating of the Czech Republic. The value of the basis ERP is 5% for whole III. regulatory period. For 2014, the risk premium for the Czech Republic is 0,85%
- β_L is weighted ratio β, which defines the sensitivity of a company share to the market risk, taking into account the income tax rate and the debt share, calculated according to the formula:

$$\beta_L = \beta_{UNLEV} \times \left[1 + (1 - T) \times \frac{D}{E}\right]$$

- $B_{unleverage}$. The regulator calculated the value for the regulatory period (0.35).
- T is the effective tax shield. The Authority will apply during the III. Regulatory period always effective tax rate. In 2014, the applied tax rate of 19%.
- The debt leverage (Ratio E/D) is set at target considered as efficient by the regulator. The ratio of debt for distribution and activities in electricity and GAS is 40% in favor of foreign capital (Debt)

Every year for applicable price indices, capital costs (depreciation allowance, WACC, RAB adjustment for activated investment and depreciation), pass through OPEX (price of electricity to cover losses) are revised and assessed the allowed revenues. Once for a regulatory period for OPEX, X-factor, and amount of electricity to cover losses are revised.

3. Tariffs for distribution services

The regulator is in charge of setting the distribution tariffs (based on allowed revenues). The methodology to allocate distribution costs is based in the reserved capacity distributed energy. There are four classes of consumers: HV, MV, LV residential, and other LV consumers. In the Czech Republic, Connection fee was defined by the regulator and hasn't changed since 2006. The customers pay a fixed fee depending of the type of connection.

3.1. Distribution tariffs

The regulator is in charge of setting the distribution tariffs (based on allowed revenues). Two categories of costs are identified:

- Modified allowed revenues (HV, MV, and LV) are recovered through reserved capacity [CZK/MW and month].
- Allowed costs of losses (HV, MV, LV) are recovered through distributed energy [CZK/MWh]

There are four classes of consumers: HV, MV, LV residential, and other LV consumers:

- HV and MV consumers are charged a distribution tariff including components:
    - "Per capacity reservation" component equal for all consumers in the same class (CZK/MW and month)
    - "Per usage of network" component equal for all consumers in the same class (CZK/MWh)
- LV consumers are charged a distribution tariff including components:
    - "Per capacity reservation" component equal for all consumers in the same class (CZK/A of circuit breaker and month)
    - per consumption - KWh charge.

There are some tariffs when the energy component is different in peak and off-peak times, in order to reflect the degree of utilization of shared distribution network assets. The start and end of off peak periods during the day are decided by each DSO based on grid conditions and activated via remote control system; the total duration of off-peaks per day has to amount to the value set out in the tariff specifications. The tariff category the customer is eligible for depends on the type of appliances they use. In LV residential are 8 tariffs from 10 have off peak and LV other are 7 tariffs from 13 have off peak.

The details of distribution tariff by voltage class and their components are summarized in section 1.2 Key figures on revenue and tariffs.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 67: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Allowed costs of losses are recovered through distributed energy component
Presence of uniform tariffs	The tariff structure applies across the country. However each DSO charges different tariff set by the regulator
Presence of non-linear tariffs	No, all tariff components are linear.
Presence of regulated retail tariffs	No
Presence of social tariffs	No

Generators connected to the distribution grid do not pay any distribution tariff. There are not special incentives in network tariffs for large users like power plants.

The distribution tariffs are published at next links:

- http://www.eru.cz/documents/10540/486799/ERV10_2012.pdf/560c98e4-2b99-453d-9917-7c09a30015aa
- http://www.eru.cz/documents/10540/486799/ERV9_2012.pdf/88d058cb-3c2a-40a4-aea4-fef5450c7f46

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 68: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	There is just fee for connection. This fee has no direct connection with real price of connection. The fee was determined to cover approximately half of the average connection cost.
	Methodology adopted to determine connection costs	Connection fee was defined by the regulator and hasn't changed since 2006. Depending of the kind of connection to grid (HV,VHV,LV level) and type of connection (A, B, 3 Phase, 1 Phase), the customers pay a fee (CZK /MW on HV and MV, CZK/A on LV).
Hosting	Scope to refuse connection	The DSO´s may refuse connection to

	Issue	Approach
capacity		the distribution of consumer or generator in case of lack of capacity
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	The DSO is assumed to have a duty to connect all the renewable capacity that applies for connection except lack of capacity in the area. There are not incentive schemes to enhance hosting capacity

The connection fee is set by the NRA. For information about connection fee, see the table below:

Connection to grid	Type of connection	Customers payment
TSO grid		200000 CZK/MW
DSO grid vhv level	Type A	600000 CZK/MW
DSO grid vhv level	Type B	150000 CZK/MW
DSO grid hv level	Type A	800000 CZK/MW
DSO grid hv level	Type B1	200000 CZK/MW
DSO lv level	3 Phase	500 CZK/A
DSO lv level	1 Phase	200 CZK/A

The difference between type A connection and type B/B1 connection are simply in the range of changes in the grid. When DSO has to build new infrastructure, then charge the customer by type A price. When DSO can connect customer to the existing grid then charge the customer by type B/B1 price.

More information is available in next link (Czech Only): http://www.eru.cz/cs/-/vyhlaska-c-51-2006-sb-

4. Distribution system development and operation

In the Czech Republic, the DSO´s do not have to notify their Network Development Plans. Only TSO development plans are submitted and approved by the NRA.

DSOs have full responsibility for metering and own the meters.

A cost-benefit analysis of smart meters done in the Czech Republic, showed negative results. There are not Smart meters implemented in the network on LV except pilot projects.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 69: Approach to distribution planning

Issue	Approach
- Form of distribution planning document	Network development plans are not notified to the regulator. Only TSO publishes development plans.
- Key responsibilities for its development	Not applicable. There is not DSO network plan.
- Degree of integration with renewables plan	Not applicable. There is not DSO network plan.
- Relationship with consumption trends	Not applicable. There is not DSO network plan.
- Relationship with quality of service targets	Not applicable. There is not DSO network plan.
- How trade-offs between network development and alternative technologies are treated	Not applicable. There is not DSO network plan.
- Requirements to integrate cost benefit analysis	Not applicable. There is not DSO network plan.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 70: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	Smaller embedded generators (like residential PV) are not dispatched. Larger embedded generators are dispatched technically by the DSO asked by system operator.
Possibility to dispatch flexible loads	Yes, the DSO can directly control flexible loads through remotely operated switches
Other sources of flexibility open to DSO	Yes, the DSO can use a remote (ripple) control system to switch on or off participating appliances

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 71: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs have full responsibility for metering and for the installation, calibration and maintenance of metering. DSO owns the meters or its service company owns the meters..
Monopoly services in the metering	Yes
Smart metering functionality	Smart Meters are under discussion.

A cost-benefit analysis performed in accordance with directive 2009/72/EC has shown negative results. The Czech Republic does not have plans for a large-scale rollout of smart meters. Smart Meters have so far been only deployed on the LV level as part of pilot projects. HV and MV level and all producers of electricity are metered by industrial meters with higher quality of metering and scope of metered data than Smart Meters offers.

Country Report – The Czech Republic (Gas distribution)

1. Overview of to the distribution sector

In the Czech Republic, the gas distribution sector is divided in concentrated mainly in six (in 2013, since 2014 there are three DSOs in the Czech Republic) regional distribution companies. There are another locals DSO which distributed to delineated areas.

Since 2007, DSO´s are legal unbundled. However DSO´s with less of 90,000 end customers have not unbundling obligations in place.

The main responsible of regulation and tariff setting is the NRA. The pricing methodology is laid down in the NRA public notice and it the same for all DSO.

1.1. Institutional structure and responsibilities

In the Czech Republic are six (in 2013, since 2014 there are three DSOs in the Czech Republic) regional distributions companies with a total of 61265 km of pipelines distributed gas. Additionally, there are local DSOs which distribute to delineated areas. These local DSOs are connected via entry points to the regional distribution system.

Distributions gas companies in Czech Republic have legal unbundling in accordance with section 59A "Separate Status of the distribution system operators" Act 458/2000 Coll. Since 2007, DSO has been in terms of legal form, organization and decision making, independent of other activities unrelated to gas distribution, gas transmission and gas storage. However for the DSO´s with less than 90000 connected end customers have not unbundling obligations in place.

Table 72: DSO characteristics in 2013

	Total number DSOs	Ownership unbundled	Legally unbundled (1)	Less than 90000 customers	Exemption *	Share of total demand
Country	79		6	73		

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**
(1) Since 2014 there are 3 large gas DSO (3 companies have merged into one company by the end 2013)

According to Energy 458/2000 COLL, The Energy Regulatory Office-ERO (Hereinafter the NRA) is the administrative authority charged with the exercise of regulatory powers in the energy sector. NRA issues principles in secondary law, define methodology, set values and calculate the allowed revenue. One of the many responsibilities of the DSO is prepare and submit to the NRA the data needed for decision on prices charged for gas distribution.

The tariff (price) decision is published by the NRA once every year. Before publication a 2-weeks consultation process is started.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 73: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO			
Government			
NRA	X	X	X

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

1.2. Key figures on revenue and tariffs

Distribution allowed revenues of all DSO in 2013 were € 564 million, broken down by the following activities:

- Depreciation – 184,992 € million (32,8%)
- Profits –153,408 € million (27,2%)
- Allowed cost – 225,600 € million (40,0%)

Distribution tariff are defined in two categories by consumer consumption:

- Medium and large off take consumers (consumption over 630 MWh/year)
- Households and small offtake consumers

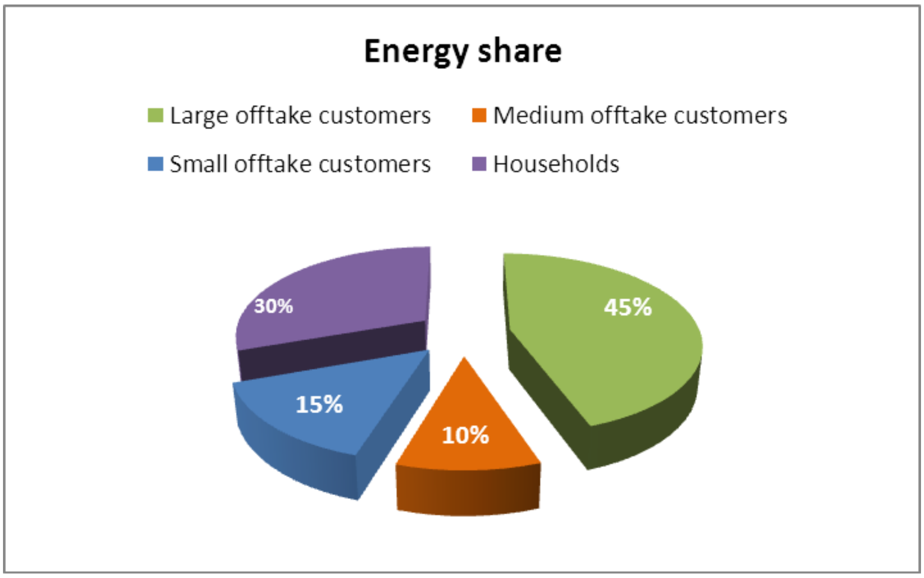
A breakdown by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

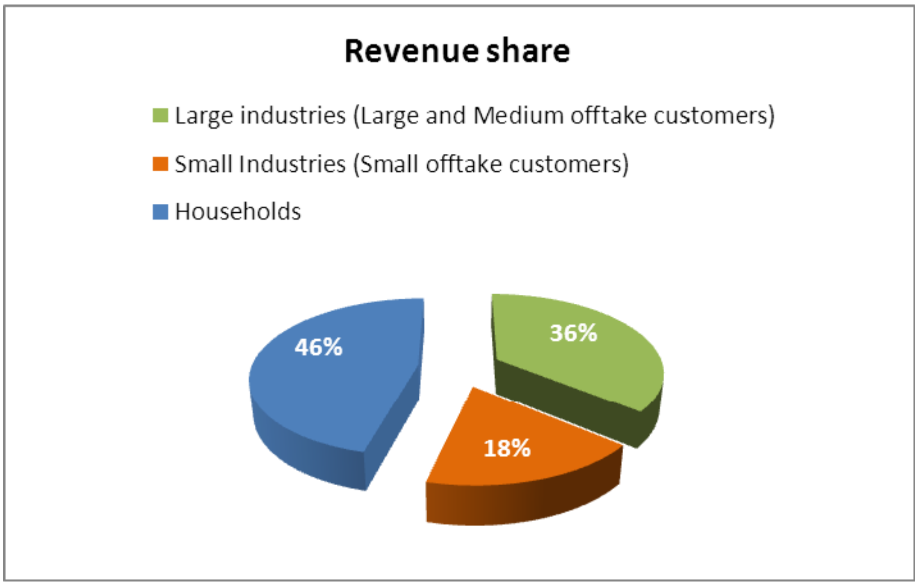
Table 74: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenue (€ million)
Large offtake customers	Capacity component, Consumption component	1637	203,040
Medium offtake customers	Capacity component, Consumption component	6946	
Small offtake customers	Capacity component, Consumption component	201274	100,956
Households	Capacity component, Consumption component	2650488	260,004
Total	-	2860345	564,000

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 31: Proportion of energy and revenue accounted by customer categories





The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below

Table 75: Breakdown of annual charges – typical customer types, 2013 (CZK)

Customer type	Notional Energy usage	Capacity component	Consumption component	Total
Households with annual consumption of 15000 kWh	15000 kWh	1467 CZK/year	2731 CZK/year	4198 CZK/year
Industrial Consumer with an annual consumption 50000 MWh and 7000 use hours	50000 MWh	2232541 CZK/year	783000 CZK/year	3015541 CZK/year
Industrial Consumer with an annual consumption 90000 MWh and 7000 use hours	90000 MWh	3687150 CZK/year	1409400 CZK/year	5096550 CZK/year

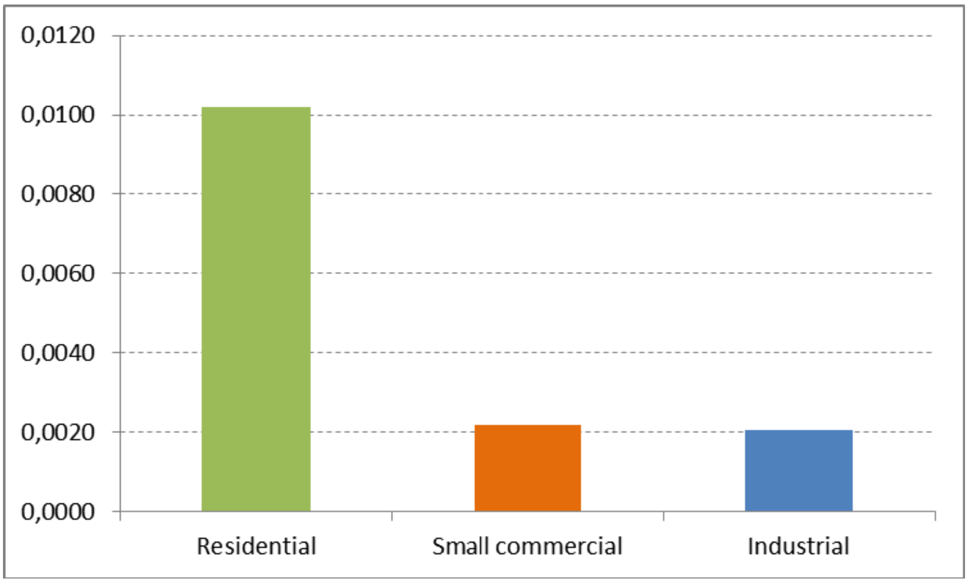
In the next table, the tariff amounts are in euros.

Table 76: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Capacity component	Consumption component	Total
Households with annual consumption of 15000 kWh	15000 kWh	53 €	98 €	151 €
Industrial Consumer with an annual consumption 50000 MWh and 7000 use hours	50000 MWh	80349 €	28180 €	108529 €
Industrial Consumer with an annual consumption 90000 MWh and 7000 use hours	90000 MWh	132701 €	50724 €	183425 €

The resulting average tariffs per kWh are illustrated below.

Figure 32: Average network charges (€/kWh), 2013



2. Regulation of distribution activities

The distribution sector is regulated under a mix of cost reimbursement and incentive based model. DSO operates in a licence regimen. Licences are not allocated through competition, every DSO who meet the requirements will get the licence The model ensures to DSO achieve the allowed revenues. The regulatory system does not place volume risk or market conditions risks on the DSO.

2.1. General overview

The Act 458/2000 COLL provides the main rules of the whole Energy Sector, including electricity distribution. The Act establishes that to develop business activities in the energy sector as distribution activities a government authorisation in the form of a licence granted by the Energy Regulatory Office is required.

According to section 25, the DSO´s shall: "Provide reliable operation and development of the distribution system in the territory delineated by the licence; Enable electricity distribution on the basis of concluded contracts; and Control the electricity flows within the distribution system while respecting electricity transmissions between other distribution systems and the transmission system, doing so in co-operation with operators of other distribution systems and the transmission system operator".

The NRA (Energy Regulatory Office- ERO) is the administrative authority to regulate the energy sector. "The mission of the Energy Regulatory Office is to support economic competition, to support the use of renewable and secondary energy sources, and to protect consumers' interests in those areas of the energy sector where competition is impossible, with the aim to meet all reasonable requirements for the supply of energy".

The distribution activities are regulated under a licence regime. Licences are not allocated through competition, been every DSO who meet the requirement will get the licence

The DSO licence is for a maximum of 25 years period. The NRA should revoke a licence to the holder in some cases, detailed in Section 10 of the Energy Act.

The broad regulatory model implement in The Czech Republic is a mix of "cost reimbursement" and "incentive based". Capital costs are subject to "cost reimbursement", while operating cost are subject to a "revenue cap" system.

Key features of the regulatory regime are set out in the following table:

Table 77: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Licence. Maximum 25 years period
Duration of tariff setting regime	Regulatory period is usually 5 years
Form of determination (distributor propose/regulator decide)	Regulator decides
Scope for appeal regulatory decision	No

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- The NRA sets cost base for regulatory period (Usually 5 years). Cost base is yearly update by price indexes and X-factor.
- The difference between set (allowed) costs and actual costs is DSO´s profit or loss. This incentive to the DSO to a cost optimization.
- In addition, targets with premiums and penalties are set on the losses.
- The allowed revenue is balanced with a two-year lag. There is an ex-post regulatory account (called correction factor) of allowed revenue, so this difference between actual and allowed revenue is settled two years later (year+2)

At the same time the following tools are provided to mitigate risks:

- The regulatory framework may be altered during the regulatory period in case the energy market conditions or general economic situation change significantly compared to the original situation.
- The cost base for each subsequent regulatory period is set based on actual costs incurred in the certain period of the previous regulatory period.
- Regulatory system does not place volume risk on the DSO. The allowed revenue target is set for particular year. If DSO does not obtain or exceed the revenue target in one year because of different demand revenues are corrected in the following year tariffs
- The revenue target is set for particular year. If DSO does not obtain or exceed the revenue target in one year because of different demand revenues are corrected in the following year tariffs. The tariff will be adjusted to make up for the missing revenue (two years later)
- Legislation allows to reassess determined parameters for regulatory period or regulatory year only in exceptional cases (e.g. supply security disruption).

Quality of service is determined by a public notice issued by The NRA. Public notice sets demanded level of provided service, deadlines for solving customer´s requests and assesses penalties for Gas market participants. In case the standard is not met the customer is entitled to a compensation payment which must be requested.

However the quality of service is not related to the distribution tariff system. No penalties /compensation are implemented in the regulatory framework.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 78: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Capital costs are subject to “cost reimbursement”, while operating cost are subject to a “revenue cap” system.
Regulatory asset base	Before this regulatory period, there was revaluation of assets because of unbundling. The current RAB is based on this revaluated (based on replacement values) book value of assets and is not further indexed
Capital expenditure	There is no approval process of investment in the regulation. There is no methodology implemented by the regulator to assess the DSO investment requirements
Approach to operating expenditure	OPEX of regulated subjects is compared only in special cases. There are not different costs assessment for some activities or special projects
Form of WACC applied	Nominal, pre-tax WACC
Additional revenue items (where applicable)	Not applicable

The following formula is applied in determining the real-pre-tax WACC:

$$WACC = \frac{R_E}{1-T} \cdot \frac{E}{D+E} + R_D \frac{D}{D+E} \cdot$$

Where:

- $R_{E:}$ is the real price of equity and own funds calculated according to the formula:

$$R_E = R_F + \beta_L \times ERP$$

- $R_{D:}$ is the cost of debt. The regulator calculated the value for the year 2014 (3.78 %).
- R_F is profitability of an risk-free asset, calculated average revenue from 10+ year government bonds issued in between May 2012 and April 2013 for the year 2014 at 2.3%,
- The NRA set ERP as the sum of the basis ERP and the Czech Republic´s risk premium. In the years of III. regulatory period the Czech Republic´s risk premium has been set on the basis of the published data on the basis points of default spread from Professor Damodaran´s database and in relation to the then current rating of the Czech Republic. The value of the basis ERP is 5% for whole regulatory period. For 2014, the risk premium for the Czech Republic is 0.85%
- β_L is weighted ratio β, which defines the sensitivity of a company share to the market risk, taking into account the income tax rate and the debt share, calculated according to the formula:

$$\beta_L = \beta_{UNLEV} \times \left[1 + (1 - T) \times \frac{D}{E}\right]$$

- $B_{unlev.}$ The regulator calculated the value for the regulatory period (0,40).
- T is the effective tax shield. The Authority will apply during the III. Regulatory period always effective tax rate. In 2014, the applied tax rate of 19%.
- The debt leverage (Ratio E/D) is set at target considered as efficient by the regulator. The ratio of debt for distribution activities in electricity and GAS is 40% debt and 60% equity. The actual DSO financial structure is not used to set on the regulated allowed revenues.

Every year for applicable price indices, capital costs (depreciation allowance, WACC, RAB adjustment for activated investment and depreciation), pass through OPEX (price of gas to cover losses) are revised and assessed the allowed revenues.

Once for a regulatory period for OPEX, X-factor, and amount of gas to cover losses are revised. The X factor is based on past performance of the companies and on international experience.

3. Tariffs for distribution services

The regulator is in charge of setting the distribution tariffs (based on allowed revenues). The methodology to allocate distribution costs is based in the partial assignment on capacity and consumption costs. Distribution tariff are defined in two categories by consumer consumption: Households and small offtake consumers and Medium and large off take consumers. The tariff structure is the same for all the DSO, but prices are different.

3.1. Distribution tariffs

The regulator is in charge of setting the distribution tariffs (based on allowed revenues). The tariffs are based on an economic approach when users pay for the costs that they generate. The allowed amount of losses defined by the NRA is part of the distribution tariffs.

The methodology to allocate distribution costs is based in the partial assignment on capacity and consumption (variable) costs. For each category of consumers the ratio between consumption and capacity is different.

Distribution tariff are defined in two categories by consumer consumption:

- Households and small offtake consumers.
- Medium and large off take consumers (consumption over 630 MWh/year)

In each category there are subcategories or bands of consumption. The following subcategories are for households and small industry:

- 63 - 630 (MWh/y)
- 55 - 63 (MWh/y)
- 50 - 55 (MWh/y)
- 45 - 50 (MWh/y)
- 40 - 45 (MWh/y)
- 35 - 40 (MWh/y)
- 30 - 35 (MWh/y)
- 25 - 30 (MWh/y)
- 20 - 25 (MWh/y)
- 15 - 20 (MWh/y)
- 7,56 - 15 (MWh/y)
- 1,89 - 7,56 (MWh/y)
- 0 - 1,89 (MWh/y)

Otherwise the Medium and large off take consumers have bands of consumption:

- High pressure
- Low and medium pressure

The tariff components are summarized in section 1.2 Key figures on revenue and tariffs. Various other aspects of distribution tariff setting are summarized in the table below.

Table 79: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Allowed costs of losses are part of allowed revenue, which is divided into capacity and energy component
Presence of uniform tariffs	General structure of tariff is geographically uniform. However each DSO has different tariff (prices) set by the regulator. No time of use tariff differentiation.
Presence of non-linear tariffs	Yes, tariffs are not linear. There are bands of consumption for households and small offtake consumers with different unit prices.
Presence of regulated retail tariffs	No
Presence of social tariffs	No

There are not special incentives in network tariffs for large users like power plants.

The distribution tariffs are published at next link (Czech only):
http://www.eru.cz/documents/10540/547837/CR_plyn_3-2012.pdf/7e954a9c-e0d6-41fe-bd7a-1b2d20c2c438

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 80: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Connection charges are not used.
	Methodology adopted to determine connection costs	Connection charges are not used.
Hosting capacity	Scope to refuse connection	DSO is allowed to refuse connection only if supply points did not meet technical and security requirements.
	Requirements to publish hosting capacity	No requirement on the DSO

4. Distribution system development and operation

In the Czech Republic, the DSO´s do not have to notify their Network Development Plans. Only TSO development plans are submitted and approved by the NRA.

DSOs have full responsibility for metering and own the meters.

A cost-benefit analysis of smart meters done in the Czech Republic, showed negative results. There are not Smart meters implemented in the network.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 81: Approach to distribution planning

Issue	Approach
- Form of distribution planning document	DSO Network development plans are not notified to the regulator nor published. Only TSO development plans are approved by The NRA and published
- Key responsibilities for its development	Not applicable.
- Degree of integration with renewables plan	Not applicable.
- Relationship with consumption trends	Not applicable.
- Relationship with quality of service targets	Not applicable.
- How trade-offs between network development and alternative technologies are treated	Not applicable.
- Requirements to integrate cost benefit analysis	Not applicable.

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 82: Key approach to metering

Issue	Approach adopted
DSO role in metering	DSOs have full responsibility for metering and own the meters.
Monopoly services in the metering	Yes
Smart metering functionality	A cost-benefit analysis performed in accordance with directive 2009/72/EC has shown negative results. The Czech Republic does not have plans for a large-scale rollout of smart meters. Smart Meters are just in pilot projects

Country Report – Germany (electricity distribution)

1. Overview of the distribution sector

Germany has a rather fragmented distribution industry, mostly controlled by state and local government. All DSOs apply functional and accounting unbundling, DSOs with more than 100000 connected customers also legal and operational unbundling, marketing and branding included. Occasionally DSOs operate (as ISOs) grids owned by third parties not affiliated with them.

1.1. Institutional structure and responsibilities

In *Germany* there are 883 distributors supplying electricity to 49.3 million customers, covering the whole country. Summary data on industry structure is set out below.

Table 83: DSO characteristics

Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
883	N.A.	N.A.t	780 (26.4% of energy)	Yes	N.A.

The responsibility for setting distribution tariffs is spread between the following jurisdictions (for example):

- Government in cooperation with the Council of the States (*Bundesrat*) issues secondary laws (ordinances), including on the framework for tariff structure rules.
- The NRA (*Bundesnetzagentur*) approves cost allocation methodologies, performs the efficiency benchmark and calculates the allowed revenues..
- The DSO applies the tariff structure consistently with the allowed revenue.
- DSOs with fewer than 100000 final customers are predominantly under the responsibility of the regulatory authorities of the German federal states (Land Regulatory Authority). Such regulatory authorities exist in Schleswig-Holstein, Lower Saxony, North Rhine-Westphalia, Rhineland-Palatinate, Saarland, Hessen, Baden-Württemberg, Bavaria, Saxony and Saxony-Anhalt

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 84: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO		Implements	Submits charging proposal
Government	Defines main principles	Issues tariff structure rules	Issues principles law
NRA/LRA	X	X	Monitors ex post

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The legislator determines the regulatory principles in primary law.

The government, partly together with Federal Council of States issues secondary laws (ordinances).

The framework for tariff structure rules are generally set in the Ordinance on Electricity Network Charges (StromNEV).

The regulator applies ordinances, provides opinions and initiates formal procedures in case of misapplication of the regulatory framework or discrimination by network operators. For each regulatory period, BNETZA calculates the allowed revenues based on DSO costs. A (non public) hearing is held before the allowed revenues are approved.

The DSO converts the revenue cap into a price sheet and tariff structure. There is no consultation on this process, as it follows rules defined by law in detail (see section 3.1 below).

1.1. Key figures on revenue and tariffs

There are about 890 German DSOs for electricity. A great number of DSOs are not directly connected to the transmission grid but to upper voltage level grids of other DSOs. For the electricity consumed from the upper level grid (and distributed to the consumers) the DSOs are charged network tariffs which are included in their annual revenues (upstream network charges). Due to this effect, the sum of allowed revenues over all DSOs is higher than the sum of tariffs charged to end costumers.

The upper level DSOs will treat lower level DSOs like end costumers within their charging methodology. Hence the sum of consumed energy on all voltage levels will contain end consumers as well as delivered electricity to lower level DSOs. Hence the data shows a higher level than net consumption.

All following data only consists of DSOs in responsibility of Bundesnetzagentur and consist of about 85-90% of total revenue. (DSOs with fewer than 100,000 final customers are predominantly under the responsibility of the regulatory authorities of the German federal states.

Such regulatory authorities exist in Schleswig-Holstein, Lower Saxony, North Rhine-Westphalia, Rhineland-Palatinate, Saarland, Hesse, Baden-Württemberg, Bavaria, Saxony and Saxony-Anhalt.) The data is based on planned values. The revenues are not approved as the final formal approval of revenues including volatile costs and permanent not controllable costs is only commenced with approval of revenues in 3RD regulatory Period starting from 2019. Revenue data do not contain revenues for elements that are not within network charges but are passed through by the DSO (e.g. concession fee, renewable energy support levy).

Planned revenues in in 2013 were €18,1 billion, broken down by the following activities:

Distribution	16,8	93%
Metering	0,17	1%
Metering point operation	0,49	3%
Customer management	0,6	3%

A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 85: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers*	Revenue
HV	KWh only	4000	500
HV/MV**	KWh only	75000	300
MV	KWh only		1400
MV/LV**	KWh only	201000	100
LV with load measure	KWh only		500
LV non load	KWh only	31586000	7500
All load measured	KW	288000	5300
Non load measured	Fixed	31586000	500
Other***	-	--	700
Total	-	--	16800

(*)For Non load measured costumers planned values are available. For all other categories the number of costumers is measured with the (planned) number of installed meters.

(**)The HV/MV respectively MV/LV level is defined for busbar to busbar. If a customer is connected to the busbar and paying tariffs for the HV/MV-level (not MV-level), he is classified as a costumer in MV

(***).Some DSOs operate small transmission voltage level grinds. Other revenues comprise of esp. of the transmission revenues. But also of other revenue elements (charges for reactive energy, *network reserve, special tariffs for night saving heating etc.)*

The breakdown of energy volumes and distribution revenue by customer category is not available.

BNetzA employs Eurostat consumer categories Eurostat (Dc, Ib and Ig):

- Household, Dc: 3500 kWh/p.a.
- Small industrial, Ib: 50000 kWh/p.a.
- Large industrial, Ig: 4000 kW, 24000000 kWh/p.a. (6000 hours)

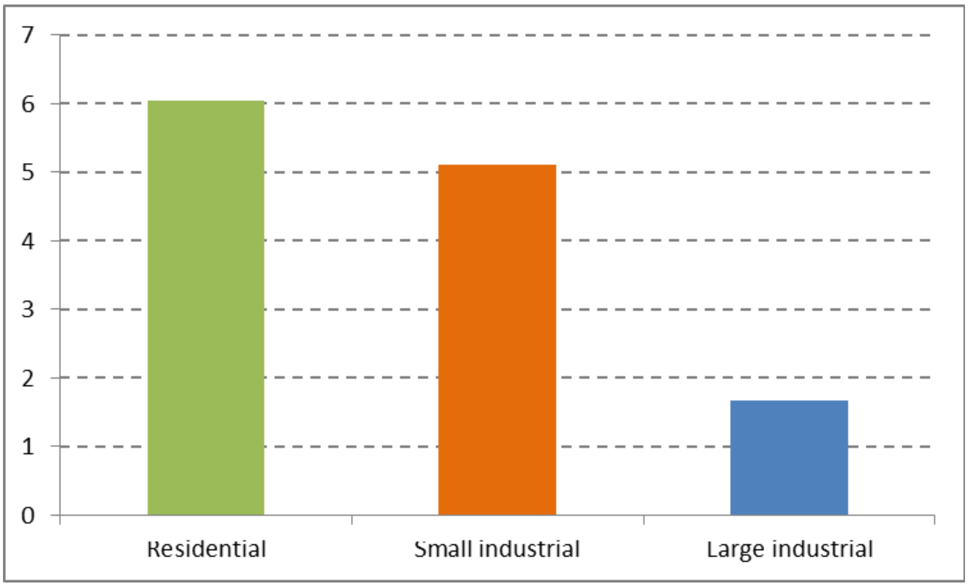
The typical network tariff in 2013 for residential, small and large industrial customers is not available, as tariffs are differentiated by DSO, and there about 880 of them. For the same reason, the share of total distribution revenues corresponding to each customer group (household, small industrial, large industrial) is not available However, the following Table shows the best available detail of the total revenue of fixed, energy related and load related tariffs, by voltage level:

Table 86: Breakdown of annual charges – typical customer types, 2013 (million €)

Customer type	Fixed charges	Energy charges	Load and reactive charges	Total
LV non load measured	500	7500	-	8000
LV – MV load measured	-	500	400-	900
HV load measured	-	500	1800	2300

The average tariffs per kWh for the typical customers in 2012 (latest available year) are illustrated below. [57]

Figure 33: Average network charges (€c/kWh), 2012



[57] In contrast to the data above these values are based on a survey of all German DSOs. (See Bundesnetzagentur und Bundeskartellamt (2013): Monitoring Report 2013 available at: http://www.bundesnetzagentur.de/cln_1422/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/DatenaustauschundMonitoring/Monitoring/Monitoringberichte/Monitoring_Berichte_node.html;jsessionid=4A93EAB609B7D046C726397F63CC1E13)

2. Regulation of distribution activities

2.1. General overview

The distribution sector is regulated under a concession regime, with a maximum duration of 20 years. Revenue cap form of incentive regulation is applied, for service expansion and for costs that cannot be influenced by the DSO or that are highly volatile, which are passed through.

Key features of the regulatory regime are set out in the following table:

Table 87: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession
Duration of tariff setting regime (regulatory period)	5 years
Form of determination (distributor propose/regulator decide)	NRA defines allowed revenue, DSO implements tariff structure methodology

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs: -

- The adoption of a TOTEX benchmarking approach for the determination of the X factor;
- The maximum share of equity (40%) for the calculation of rate of returns;
- The use of a quality parameter for the repayment of the benefits of reduced service interruptions.

At the same time the following tools are provided to mitigate risks:

- Regulatory account, which is settled at the end of the 5-year regulatory periods unless realized revenues exceed the revenue cap by more than 5%, in such case tariffs must be reduced; If revenues are more than 5% below the revenue cap, tariffs can be increased previous to the end of the regulatory period.
- Expansion factor. In case that the distribution task of the DSO changes (measured by different output indicators such as supplied area, number of connection points, annual peak load, number of feed-in points of distributed generation) and costs increase by more than 0,5% the DSO may apply for a factor increasing the revenue cap. Network related capex is normally accepted by the regulator, as efficiency is promoted by the TOTEX benchmarking;
- Use of actual financial costs, within the limits of normal practice for similar companies;
- The use of standard cost parameters related to the expansion of the service.

Key components of quality of service regulation are:

- Service quality
- Grid capacity
- Technical standards
- Interruptions, measured by SAIDI and ASIDI indices.

Only the latter is related to tariffs. The individual level of quality of supply of the respective network operator is measured against a key performance indicator reflecting the average level of quality of supply. Underperformers incur a penalty, outperformers receive a reward.

The revenue cap is adjusted by the X-component considering that the network industry has specific productivity gains, which are different from the overall economy.

The general sector-specific productivity factor results from the difference between the grid-specific economic productivity progress and the general economic productivity progress, as well as the difference between the general development of acquisition prices and the development of grid specific acquisition prices.

The factor is based on data from grid operators from the entire German territory going back at least four years. For the first periods the X-component was set to 1.25%. In the second period 1.5% is applied.

There is also a DSO-specific productivity factor, which is calculated as follows:

- After an assessment of the costs, the regulator splits total costs (e.g. € 150 m) into so-called "non-controllable costs" (which are not benchmarked, e.g. taxes, concessions etc.; e.g. € 50 m) and the residual costs (e.g. € 100 m). The residual costs are benchmarked using the DEA and SFA methods.
- The costs serve as input, and the output is the supply task of the DSOs, defined by ca. 10 parameters (e.g. area supplied, peak load, meters etc.).

The individual efficiency values that result from the benchmarking (e.g. 80%) are used to divide the residual costs (€ 100 m) into "temporarily non-controllable costs" (efficient costs; € 80 m) and "controllable costs" (inefficient costs; € 20 m).

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 88: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue cap
Regulatory asset base	Used actual value at historical costs at least 60%; revaluated starting from oldest for max. 40%
Capital expenditure	Expansion factor
Approach to operating expenditure	Actual and benchmarking
Form of capital remuneration applied	Actual financial costs, up to a max E/D+E of 40%
Additional revenue items (where applicable)	Research funds provided by state. Quality remunerations for reduced interruptions. Non controllable costs (e.g. concession fees, cost of required smart meters) are passed through..

In contrast to other EU Member States, the regulatory framework in Germany does not use WACC and RAB, but instead takes into account the effective capital structure of the DSO.

New assets (capitalised since 01.01.2006) are valued at historical costs.

Old assets (capitalised before 01.01.2006) are valued at replacement costs if they are financed by equity (indexed historical cost, maximum equity ratio of 40%) and at historical costs if they are financed by debt capital (debt ratio at least 60% of all old assets).

The return on equity for new assets is currently set at 9.05 % pre-tax (nominal) and 7.39% post-tax for the second regulatory period (for both electricity and gas as well as TSO and DSO levels).

The return on equity is determined using the Capital Asset Pricing Model (CAPM):

- Risk premium: 3,59%
- Beta: 0,79
- Market risk premium: 4,55%
- Risk free rate: 3,8%
- Inflation: 1,56%

The allowed rate of return is updated in advance of each regulatory period. The return on equity on old assets is lower as inflation is already considered in the replacement costs.

To the extent the equity exceeds 40 %, the excess portion of such equity is covered at an interest level, which is calculated as an arithmetic mean of the yields on debt securities outstanding issued by residents (in detail - public debt securities, corporate bonds (excluding non-profit institutions at banks [MFIs]), mortgage bonds). These yields are published by the German Central Bank (Deutsche Bundesbank) and as arithmetic means for the last ten completed calendar years. For electricity (base year 2011 it is 3,98 %.

3. Tariffs for distribution services

A detailed methodology based on cost cascading is envisaged for the determination of tariff structures. Several tariff options are available for higher or lower utilization rates. Smaller customers pay standing charges and energy related charges.

3.1. Distribution tariffs

The following approach is adopted to allocate costs between customer categories with the following key features:

1. Parameters required to allocate the distribution costs:

- specific annual cost (so-called “postage stamp”)

- so-called “concurrency function” (g-function)

First of all the DSO must calculate the specific annual cost for each voltage level. The specific annual cost are called “postage stamp”:

$$\textit{postage stamp} = \frac{\textit{full costs of voltage level}}{\textit{annual simultanious peak load}}$$

The g-function allocates a concurrency degree between 0 and 1 to the final customers.

The concurrency degree reflects the probability which proportion the sampling point of the customer (at time of annual peak load) takes from the simultaneous annual peak load of all sampling of this grid or transformer level.

g1: Starting point of the first line, t= between 0 and 0,2 operating hours (is set by the DSO)

g2: Starting point of the second line, t=2500 operating hours

2. <u>Methodology to calculate tariffs for load measured final customers</u>

a) Tariff for customers with fewer than 2500 operating hours:

Capacity charge <2500 = $g1 * \text{Briefmarke}$

Energy charge <2500 = $\left[\frac{g2 - g1}{2500}\right] * \text{Briefmarke} * 100$

b) Tariff for customers with more than 2500 operating hours:

Capacity charge >2500 =

$$\left[1 - (1 - g2) * \frac{8760}{8760 - 2500}\right] * \text{Briefmarke}$$

energy charge >2500 = $\left[\frac{1 - g2}{8760 - 2500}\right] * \text{Briefmarke} * 100$

3. <u>Methodology to calculate tariffs for non-load measured final customers</u>

The tariff consists of a basic charge and an energy charge (per used kWh). After setting a basic charge, the DSO calculates the energy charge by dividing the low voltage level costs (excluding performance-based final customers) reduced by basic price part (basic price * final customers) by the amount of predicted annual consumption.

Hence, the tariff structure implies that:

- Lower tariffs apply for higher consumption and voltage level;
- Customers with over 2500 hours utilization have higher peak related and lower energy related charges.
- Tariffs for measurement, metering point operation and accounting are calculated by dividing all cost centre costs by the predicted volume.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 89: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included in distribution tariffs
Presence of uniform tariffs	No, each DSO has separate tariffs
Presence of non-linear tariffs	No
Presence of regulated retail tariffs	No
Presence of social tariffs	No

There is no G- component, but power plants connected to distribution network receive an avoided cost allowance related to costs of upper voltage levels.

Different tariffs per voltage level:

Tariffs in higher voltage level must be lower than lower voltage tariffs for the same consumption profile.

Load-measured consumers (see 2.2. above) have a per KW per year and KWh charge, to be defined in this way:

- For Full load hours<2500 : higher kwh and lower kw/a.
- For full load hours>2500 : lower kwh and higher kw/a.
- For full load hours=2500: Both price systems must result in same tariff.

Non-load measured consumers pay a lump sum (fixed charge) and kwh charge

Special tariffs apply for:

a) So-called “Atypical customers” (Peak load differs significantly from peak in grid): 20% less than normal tariff.

b) So-called “Intensive customers” (Full load hours >7000 and consumption > 10 Gwh): Individual tariff with 10-20% discount on regular tariff. Tariff depends on physical proximity of load to local generation.

c) New or enlarged pump storages, which are exempted from network tariffs for 20 years.

d) Short time consumers, who are eligible for monthly kw and kwh prices.

e) Interruptible load in low voltage area (in particular night saving heating), who are granted special reduced tariffs, often with separate prices for daytime and nighttime.

f) Network reserve: pay reduced network tariffs for consumers only using the network for fewer than 600 h/a (typically consumers with own generation).

3.2. Connection and capacity issues

Key issues in the setting of connection charges are set out in the table below.

Table 90: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Deep
	Methodology adopted	DSO estimates, customer chooses supplier
Hosting capacity	Scope to refuse connection	No
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	No target but the expansion factor is an incentive to enhance capacity if needed

The connection charge is meant to cover the cost of the facilities that are specifically set up to serve the customer and the connection to his housing. In addition, the consumer is obliged to pay a contribution towards the cost of the reinforcement of networks and shared resources.

Consumers are obliged to pay the costs for the building connection and a contribution towards the network costs.

The DSO prepares an estimate based on its cost but the customer is free to procure the necessary works from a different provider.

For consumers and generators alike, the DSO may refuse connection only if it is impossible or if it would entail an unreasonable cost.

Upon request of the requesting party, in the case of lack of capacity the reasons must also contain meaningful information regarding the concrete measures and the costs associated therewith would be individually necessary for development of the system to achieve connection to the system.

4. Distribution system development and operation

Decisions are taken by DSOs, which have an obligation to supply all customers

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 91: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Network status report to NRA on HV level
- Key responsibilities for its development	DSO
- Degree of integration with renewables plan	Net development based on regionalises RES development plan
- Relationship with consumption trends	Demand trend must be taken into account
- Relationship with quality of service targets	No explicit connection
- How trade-offs between network development and alternative technologies are treated	No
- Requirements to integrate cost benefit analysis	No

For the high voltage level (110 kV), DSOs must issue a network status report to the regulator. On the basis of this report BNetzA may require the TSO to prepare a network development plan (see 1.9 above). No such distribution system development plan has ever been requested so far.

4.2. Distribution system operations

The key features of distribution system operations in dispatching are summarized below. Beside this they are responsible for development (see above), network expansion, maintenance and connection.

Table 92: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	Full dispatching authority by DSO. Dispatching priority for RES
Possibility to dispatch flexible loads	Yes
Other sources of flexibility open to DSO	No, but many DSOs are analysing battery storage potential

DSOs are allowed to dispatch flexible load. On the 110kV-level 2 out of 55 DSOs currently dispatch flexible loads. 6 other DSOs plan to do this in future.

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 93: Key approach to metering

Issue	Approach adopted
Discos role in metering	Primary responsibility
Monopoly services in the metering	No, customers can choose another provider
Smart metering functionality	N.A.

BNetzA estimates that ca. 370,000 metering points (app. 1% of all metering points) are equipped with smart meters (i.e. electronic bidirectional meters).

The Ministry of Economics and Energy (BMWi) has performed a cost benefit analysis and envisages a corresponding rollout plan that aims to install smart meter for households with an annual consumption of more than 6000 kWh, for small sized generators (*prosumers*) and for new buildings. It is estimated that this mandatory rollout will result in 30-50% of all metering points being equipped with smart meters. No relevant legislation has been introduced so far.

No breakdown by customer category is available.

No further preliminary information on the impact of smart meter roll out is available.

Country Report – Germany (gas distribution)

1. Overview of the distribution sector

Germany has a rather fragmented distribution industry, mostly controlled by state and local government. All DSOs apply information and accounting unbundling, DSOs with more than 100000 connected customers also legal and operational unbundling, marketing and branding included. Occasionally DSO operates (as an ISO) a grid owned by a third party not affiliated with DSO.

1.1. Institutional structure and responsibilities

In *Germany* there are 720 distributors supplying gas to over 14 million customers, covering almost the whole country. Summary data on industry structure is set out below.

Table 94: DSO characteristics

Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
728	N.A.	N.A.t	640 (56,8% of energy)	N.A.	N.A.
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**					

The responsibility for setting distribution tariffs is spread between the following jurisdictions (for example):

- Government in cooperation with the Council of the States (*Bundesrat*) issues secondary laws (ordinances), including on the framework for tariff structure rules.
- The NRA (*Bundesnetzagentur*) approves cost allocation methodologies, performs the efficiency benchmark and calculates the allowed revenues.
- DSOs with fewer than 100000 final customers are predominantly under the responsibility of the regulatory authorities of the German federal states (Land Regulatory Authority). Such regulatory authorities exist in Lower Saxony, North Rhine-Westphalia, Rhineland-Palatinate, Saarland, Hessen, Baden-Württemberg, Bavaria, Saxony and Saxony-Anhalt

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 95: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO		Implements	Submits charging proposal
Government	Defines main principles	Issues tariff structure rules	Issues principles law
NRA/LRA	X	NRA approval	Monitors ex post

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The legislator determines the regulatory principles in primary law.

The government, partly together with the Federal Council or Council of States (Bundesrat) issues secondary laws (ordinances).

The framework for tariff structure rules are generally set in the Ordinance on Gas Network Charges (GasNEV).

The regulator applies ordinances, provides opinions and initiates formal procedures in case of misapplication of the regulatory framework or discrimination by network operators. For each regulatory period, BNETZA calculates the allowed revenues based on DSO costs. A (non public) hearing is held before the allowed revenues are approved.

The DSO converts the revenue cap into a price sheet and tariff structure. There is no consultation on this process, as it follows rules defined by law in detail (see section 3.1 below).

1.2. Key figures on revenue and tariffs

Distribution revenues in in 2013 were €4,5 billion for DSOs under the responsibility of BNetzA, broken down by the following activities. No further segmentation is available.

Transmission and upstream costs and biogas-related costs are included. Other cost elements that are passed through by the DSO (e.g. concession levy) are however not included.)

Separate tariff components are network use, metering, metering point operation, billing and concession levy.

There are no official consumer categories. In line with Eurostat, consumers below 1,500,000 kWh are classified as standard load profile (SLP), whereas those above this threshold are load metered (RLM)

The typical network tariff in 2013 for residential, small and large industrial customers is not available, as tariffs are differentiated by DSO, and there are about 720 of them. For the same reason, the share of total distribution revenues corresponding to each customer group (household, small industrial, large industrial) is not available.

2. Regulation of distribution activities

2.1. General overview

The distribution sector is regulated under a concession regime, with a maximum duration of 20 years. Revenue cap form of incentive regulation is applied, for service expansion and for costs that cannot be influenced by the DSO or that are highly volatile, which are passed through.

Key features of the regulatory regime are set out in the following table

Table 96: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession
Duration of tariff setting regime (regulatory period)	5 years
Form of determination (distributor propose/regulator decide)	NRA defines allowed revenue, DSO implements tariff structure methodology
Scope for appeal regulatory decision	N.A.

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs: -

- The adoption of a TOTEX benchmarking approach for the determination of the X factor;
- The maximum share of equity (40%) for the calculation of rate of returns.

At the same time the following tools are provided to mitigate risks:

- Regulatory account, which is settled at the end of the 5-year regulatory periods unless revenues exceed revenue cap by more than 5%, in such case tariffs must be reduced. If revenues are more than 5% below the revenue cap, tariffs can be increased previous to the end of the regulatory period.
- Expansion factor: In case that the distribution task of the DSO changes (measured by different output indicators such as supplied area, number of exit points, annual peak load) and costs increase by more than 0,5% the DSO may apply for a factor increasing the revenue cap;
- Network related capex is normally accepted by the regulator, as efficiency is promoted by the TOTEX benchmarking;
- Use of actual financial costs, within the limits of normal practice for similar companies;
- The use of standard cost parameters related to the expansion of the service.

No quality of service regulation has been implemented yet.

The revenue cap is adjusted by the X-component, considering that the network industry has specific productivity gains, which are different from the overall economy.

The general sector-specific productivity factor results from the difference between the grid-specific economic productivity progress and the general economic productivity progress, as well as the difference between the general development of acquisition prices and the development of grid specific acquisition prices.

The factor is based on data from grid operators from the entire German territory going back at least four years. For the first two periods the X-component was set to 1,25%. In the second period 1,5% is applied.

There is also a DSO-specific productivity factor, which is calculated as follows:

- After an assessment of the costs, the regulator splits total costs (e.g. € 150 m) into so-called "non-controllable costs" (which are not benchmarked, e.g. taxes, concessions etc.; e.g. € 50 m) and the residual costs (e.g. € 100 m). The residual costs are benchmarked using the DEA and SFA methods.
- The costs serve as input and the output is the supply task of the DSOs defined by ca. 10 parameters (e.g. area supplied, peak load, meters etc.).
- The individual efficiency values that result from the benchmarking (e.g. 80%) are used to divide the residual costs (€ 100 m) into "temporarily non-controllable costs" (efficient costs; € 80 m) and "controllable costs" (inefficient costs; € 20 m).

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 97: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue cap
Regulatory asset base	Used actual value at historical costs at least 60%; revaluated starting from oldest for max. 40%
Capital expenditure	Expansion factor applied related to output (network, peak load, area, connection points
Approach to operating expenditure	Actual and benchmarking
Form of capital remuneration applied	Actual financial costs, up to a max E/D+E of 40%
Additional revenue items (where applicable)	Research funds provided by state. Quality remunerations for reduced interruptions. Non controllable costs (e.g. concession fees, cost of smart meters) are passed through.

In contrast to other EU Member States, the regulatory framework in Germany does not use WACC and RAB, but instead takes into account the effective capital structure of the DSO.

New assets (capitalised since 01.01.2006) are valued at historical costs.

Old assets (capitalised before 01.01.2006) are valued at replacement costs if they are financed by equity (indexed historical cost, maximum equity ratio of 40%) and at historical costs if they are financed by debt capital (debt ratio at least 60% of all old assets).

The return on equity for new assets is currently set at 9.05 % pre-tax (nominal) and 7.39% post-tax for the second regulatory period (for both electricity and gas as well as TSO and DSO levels).

The return on equity is determined using the Capital Asset Pricing Model (CAPM):

- Risk premium: 3.59%
- Beta: 0.79
- Market risk premium: 4.55%
- Risk free rate: 3.8%
- Inflation: 1.56%

The allowed rate of return is updated in advance of each regulatory period. The return on equity on old assets is lower as inflation is already considered in the replacement costs.

To the extent the equity exceeds a portion of 40 %, the excess portion of such equity is covered at an interest level, which is calculated as an arithmetic mean of the yields on debt securities outstanding issued by residents (in detail - public debt securities, corporate bonds (excluding non-profit institutions at banks [MFIs]), mortgage bonds). These yields are published by the German Central Bank (Deutsche Bundesbank) and as arithmetic means for the last ten completed calendar years. For gas (base year 2010) it is 4.19 %

3. Tariffs for distribution services

No detailed criteria are envisaged for the calculation of tariff structures, but only a set of general principles. Capacity related charges are used for load meered connection points, and normally cover most of the costs.

3.1. Distribution tariffs

The GasNEV does not prescribe a specific calculation model to derive network charges. A number of criteria to be met by the calculation model are however set out:

- Tariffs must be non-discriminatory;
- Tariffs shall be set in a way that the difference between the actual revenue and the distribution costs is as small as possible.

Gas DSOs must set both commodity and capacity charges. The allocation of costs to capacity and commodity charges is required to be “adequate“ (§ 18 (5) GasNEV). The ordinance does not specify a fixed split. In practice most DSOs apply a 30% (commodity) / 70% (capacity) split.

The tariff structure is as follows:

- Annual consumption of up to 1,5m kWh and a maximum exit load of 500 kWh/h: A tariff consisting of a basic charge (per month) and an energy-related charge is applied.

- Within the range (0-1,5m kWh) there are several steps with increasing basic charges and decreasing energy related charges. The lowest basic charge and the highest energy related charge is applied in case of a low annual consumption. This structure is applied for standard load profile (SLP) customers
- Annual consumption above 1,5m kWh/a: Tariffs consist of a price per kWh and a price per kW where both prices are derived out of respective formulas. This structure is applied for load-metered (RLM) customers.

If justified, the DSO may change the threshold of 1,5m kWh/a to a higher or lower value.

Large gas users are mostly connected to the transmission system and pay the ordinary tariff applied by the TSOs

Charges for network usage, metering, metering point operation and billing are shown separately on the bill. Various other aspects of distribution tariff setting are summarized in the table below.

Table 98: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included in distribution tariffs
Presence of uniform tariffs	No, each DSO has separate tariffs
Presence of non-linear tariffs	Yes
Presence of regulated retail tariffs	No
Presence of social tariffs	No

Costs resulting from activities related with biogas and quality conversion (local conversion of gas quality as well as network adaption from L- to H-gas) are funded via additional tariff components.

3.2. Connection and capacity issues

Key issues in the setting of connection charges are set out in the table below.

Table 99: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Deep
	Methodology adopted	DSO sets by standard costs
Hosting capacity	Scope to refuse connection	No
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	No target but the expansion factor is an incentive to enhance capacity if needed

For residential and small low pressure consumers and for residential installations (below 100 mbar) a uniform one-off connection fee set by the DSO applies.

For larger consumers (above 100 mbar) and generators connection costs are computed case by case. The DSO prepares an estimate based on its cost but the customer is free to procure the necessary works from a different provider.

For consumers and generators alike, the DSO may refuse connection only if it is impossible or if it would entail an unreasonable cost.

Upon request of the requesting party, in the case of lack of capacity the reasons must also contain meaningful information regarding the concrete measures and the costs associated therewith would be individually necessary for development of the system to achieve connection to the system

4. Distribution system development and operation

Decisions are taken by DSOs, which have an obligation to supply all customers, except if an unreasonable connection cost applies.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 100: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Not applicable
Key responsibilities for its development	DSO
Degree of integration with renewables plan	Not applicable
Relationship with consumption trends	Not applicable
Relationship with quality of service targets	Within ordinance on incentive regulation
How trade-offs between network development and alternative technologies are treated	Not applicable
Requirements to integrate cost benefit analysis	No

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 101: Key approach to metering

Issue	**Approach adopted**
Discos role in metering	Primary responsibility
Monopoly services in the metering	No, customers can choose another provider, but very few in practice
Smart metering functionality	Not applicable

Smart gas meters are not covered by BNetzA's monitoring report.

There are no useful applications available for the gas market at present.

Country Report – Denmark (electricity distribution)

1. Overview of the distribution sector

In Denmark, the distribution sector consists of 71 DSOs, most of which have less than 100000 end customers. 20% of end customers are served by the largest DSO which is partly owned by the government. Competences for energy regulation in Denmark are split between the Danish Energy Regulatory Authority (DERA)and the Danish Energy Agency.

1.1. Institutional structure and responsibilities

In *Denmark* there are around 70 distributors supplying electricity to more than 3 million customers with an overall circuit length of 168592 km. Summary data on industry structure is set out below.

Table 102: DSO characteristics

	Total number DSOs	**Ownership unbundled**	**Legally unbundled**	**Less than 100000 customers**	**Exemption***	**Share of total demand**(DSOs <100,000 customers)
Country	71	0	71	64	No	29,8% (in 2012)
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

The responsibility for setting distribution tariffs is spread between the following jurisdictions (for example):

- The DSO
- The NRA (The Danish Energy Regulatory Authority –DERA-)
- Government (Ministry of Climate, Energy and Building)
- Parliament

The breakdown of responsibilities as it is related to tariff setting is summarized in the table below.

Table 103: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges	Regulated services
DSO	Provide data to NRA	N/A	N/A	N/A
Government	Issue detailed methodology for the revenue caps	N/A	N/A	N/A
NRA	X	N/A	N/A	N/A
Parliament	Defines main principles and issue the general methodology	N/A	N/A	N/A

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adopted to setting distribution tariffs involves the following steps:

- The Parliament issues the principles in the primary law and issues the general methodology. The Parliament also sets the value for the maximum return on investment a DSO can obtain (a specific bond +1 pct.)
- The Ministry issues a detailed methodology for the revenue caps.
- The NRA calculates the allowed revenue on the basis of data provided by the DSO. If the DSO has obtained excess revenue, the regulator approves the settlement plan for the DSO to give the money back to the consumers.

1.2. Key figures on revenue and tariffs

The sum of revenue caps in *Denmark* 2012[58] were DKK 6730345411[59]. No further split by service type or number of customers in each category is available.

2. Regulation of distribution activities

The distribution sector is regulated under a concession regime. An “incentive-based” form of regulation is applied with a revenue cap system combined with a maximum level of return on

[58] DKK 6 670 145 717 is the sum of revenue caps in Denmark for 2013. The number is under revision at the moment.
[59] This number is the maximum revenue cap. However some companies are bound by a maximum return on capital, so this number is higher than the real number.

2.1. General overview

The Danish Energy Regulatory Authority (DERA) regulates the Danish markets for electricity, natural gas and district heating. In the electricity market, the regulation focuses on the network companies. However, DERA also sets the allowed price for electricity companies with an obligation to supply (i.e. the companies that supply customers who have not chosen their own supplier in the free market).

The distribution sector is regulated under a concession regime. Concessions last for a period of 20 years. They will be renewed in the period of 2021-24. Concessions are not allocated through a competitive mechanism. When introducing the concession-regime the concessions where allocated for distributors who were already distributors in the specific geographical area. If a DSO loses a concession the reimbursement of non-depreciated investments is unclear under Danish legislation. Withdrawal of a concession is possible under certain circumstances, and – in majority of cases – subject to a judge's decision (because of expropriative character of such a decision). There is an obligation on previous concessionaire to make installations available to new concessionaire. Minister can in such cases tender a concession. In the interim, the minister can enjoin Energinet.dk to carry out the activity. In those cases, the DSO losing the concession may retain ownership of installations, and the new concessionaire is exempted from the otherwise applicable legal obligation that the one who has the concession has to have ownership of installations. The previous DSO is obliged to make installations available "at reasonable terms."

An "incentive-based" form of regulation is applied with a revenue cap system combined with a maximum level of return on capital and benchmarking of depreciations, operating costs and quality in supply.

The distribution tariff is itemized separately to end-users.

Key features of the regulatory regime are set out in the following table:

Table 104: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concessions
Duration of tariff setting regime	The current regulatory period has been in place since the beginning of 2005, and revenue caps are dependent on the DSOs income in 2004. The revenue caps are announced every year.
Form of determination (distributor propose/regulator decide)	Regulator decides
Scope for appeal regulatory decision	DERA decisions can be appealed to the Energy Board of Appeal

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Allowed revenues depend on kWh delivered through the distribution network.
- Since income is restricted by a revenue cap, the DSO is incentivised to reduce costs.
- Since return on capital is restricted by a maximum level of return on capital, the DSO is incentivised to reduce costs to increase profits until it reached the maximum allowed level.
- The DSO is also incentivised to reduce costs while maintaining quality in supply by an annual benchmarking of depreciations, operating costs and quality in supply. The outcome of benchmarking is reductions in the revenue cap. The revenue cap does however strongly depend on demand (because the largest part of the revenue cap is calculated on the basis of a price cap).
- Certain types of investment can lead to an increase in revenue cap corresponding to an amount which covers depreciation, differences in operating expenses, and a set percentage of return on investment. For instance, this is the case for investments which replace overhead power lines by underground cables.

At the same time the following tools are provided to mitigate risks:

- If DSOs do not set tariffs such that the revenue cap is not fully utilised, the gap between income and revenue cap can be transferred to the following two years. That is, allowed revenue in the following two years will increase in this case. On the other hand, if income exceeds tariffs by a certain amount of money, the DSO must pay back this amount by lowering tariffs over the following two years.
- If revenues fall short of the revenue cap because of a reduction in demand, the missing revenues can be recovered over the following two years. Differences between actual and allowed revenue must be collected or paid back over the following two years.
- DSOs are benchmarked against each other on operating costs. If however an extraordinary event occurs which forces extraordinary costs on the DSO in a particular year, the DSO can apply for an exemption of these costs from benchmarking.

Key components of quality of service regulation are:

- DSOs are benchmarked on quality in supply which includes the number and duration of interruptions in supply.
- Allowed revenues are decreased if the DSO performs worse than certain thresholds.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 105: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue cap combined with a maximum rate of return
Regulatory asset base	Book value
Capital expenditure	Benchmarked
Approach to operating expenditure	Benchmarked
Form of capital remuneration applied" (WACC real, nominal, ten years Treasury bond + adder, …)	No explicit remuneration is secured because the income cap are set on the grounds of the actual revenue in 204"
Additional revenue items (where applicable)	N/A

The allowed rate of return is fixed annually as the average long mortgage bond rate plus one percentage point. The allowed rate of return does not depend on the financial structure of DSOs in Denmark.

The allowed revenue is bound by two ceilings, 1) the revenue the DSO had in year 2004 and 2) a maximum return on capital.

Revenue caps are calculated by the following method:

1) In 2004, the DSO's revenues are divided by delivered kWh which gives a so called regulatory price.

2) The revenue cap in each following year is obtained by multiplying the inflation-adjusted regulatory price by delivered kWh in this year. A number of adjustments on the revenue cap is carried out. For example, if DSOs change accounting methodologies when comparing to 2004.

3. Tariffs for distribution services

Costs are split on the voltage-level .Fixed costs are billed through subscription and costs that vary in the amount delivered are variable costs. Each DSO sets different tariffs. For small consumers the connection cost is a standard cost calculated by standard needs and standard costs. For larger consumers a calculation is done on the basis of an average grid. The DSO is not allowed to refuse connection of consumers and generators.

3.1. Distribution tariffs: additional issues

The distribution company is in charge of setting the distribution tariffs (based on allowed revenues). However, the method of setting tariffs must be approved by the regulator.

Costs are split on the voltage-level. This is done with either a direct distribution, with used MWh, or by the number of consumers depending on the nature of the cost. From here they are split on either the variable tariff or the subscription. The rule of thumb is that the fixed costs are billed through subscription and costs that vary in the amount delivered is variable costs.

Consumer classes are divided from their point of entry in the grid. A, B and C consumers is used. C-consumers entry point is the low-voltage network. The point of entry is decided by amount delivered. All consumers pay a subscription that is equal for all in the same class. And then a variable tariff depending on the amount delivered, that covers both costs in their own voltage-level, but also the costs caused upward in the system.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 106: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	The revenue cap is not dependent on the actual oses (but only the price of energy). This implies that DSOs can benefit from reducing loses
Presence of uniform tariffs	Each DSO sets different tariffs.
Presence of non-linear tariffs	All tariff components are linear.
Presence of regulated retail tariffs	None
Presence of social tariffs	None

There's no time of use differentiation except for large consumers with consumption above 100.000 kWh.

The costs for the DSOs energy-saving activities is included in the distribution tariff.

3.2. Connection and capacity issues

For residential and small BT consumers and for residential installations a uniform one-off connection fee set by the DSO applies. For larger consumers and generators connection costs are computed case by case.

Key issues in the setting of connection charges are set out in the table below.

Table 107: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Shallow charges
	Methodology adopted	For small consumers the connection cost is a standard cost calculated by standard needs and standard costs. For larger consumers a calculation is done on the basis of an average grid. The calculation covers what the costs of building an average grid from daily prices and technology and how many ampere the consumer

	Issue	Approach
		requires. The DKK/A is then multiplied by how much capacity the consumer needs.
Hosting capacity	Scope to refuse connection	The DSO is not allowed to refuse connection of consumers and generators. Anyone has the right to use the collective grid to transport electricity against payment.
	Requirements to publish hosting capacity	None
	Targets and/or incentive schemes to enhance hosting capacity	None, the DSO is assumed to have a duty to connect all the capacity that applies for connection

4. Distribution system development and operation

DSOs can demand that the embedded generator is removed from the collective grid when making work on the grid. As of 2013 there were 1,719,531 smart meters installed in Denmark. DSOs have to extend the installation of smart meters to all end customers by the year 2020.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 108: Approach to distribution planning

Issue	Approach
Form of distribution planning document	
- Key responsibilities for its development	There is no public system development plan for Danish DSOs.
- Degree of integration with renewables plan	RES targets are not set on a regional level. Internal plans are developed by DSOs based on known and expected RES sites.
- Relationship with consumption trends	The evolution of consumption in the distribution area is considered in internal plan. Flexibility might play a role in future planning if the regulation offers the right incentives for investment.
- Relationship with quality of service targets	Quality of service targets are considered when general system layout is determined. Cost benefit Analysis (CBA) is generally not used in this respect.
- How trade-offs between network development and alternative technologies are treated	N/A
- Requirements to integrate cost benefit analysis	N/A

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 109: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	DSOs can demand that the embedded generator is removed from the collective grid when making planned work on the grid. They have to give notice in good time. If a situation arises that require immediately work on the grid the DSO can remove it without warning. The DSO can remove the embedded generator from the collective grid without warning also in cases of breach of contract.
Possibility to dispatch flexible loads	None
Other sources of flexibility open to DSO	None

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 110: Key approach to metering

Issue	Approach adopted
DSOs role in metering	a) DSOs own most part of the meters b) DSOs are responsible for the collection of data from the meter c) the DSOs are responsible for sending the information to a Datahub. This datahub is controlled by the TSO which also has the responsibility for the easy access to that data for relevant third-parties.
Monopoly services in the metering	DSOs are monopolists in metering activities
Smart metering functionality	The technical requirements for smart meters are provided by the executive order about smart meters and metering of electricity consumption. (https://www.retsinformation.dk/Forms/R0710.aspx?id=160434). This shows that the smart meters should be able to: a) quarter-of an hour measurement (registration every 15 minutes or at shorter intervals) b) remote reading f) local port to send real time consumption information to a local screens or computers In addition, the smart meters should be able to: • Change the settings for the recording rate via a remote reading system • Store the measured data for use of billing • Register supply interruptions and on request from the grid company transfer data about interruptions • Show accumulated values delivery of electricity and the current electrical power Finally, it should be possible for the consumer by open standards to connect external devices to the remote reading of smart meters and extract relevant current consumption data.

As of 2013 there were 1,719,531 smart meters installed in Denmark.

The Danish Energy Agency issued in December 2013, an executive order requiring to network operators to install electricity smart meters for all electricity consumers by the year 2020.

Country Report – Denmark (Gas)

1. Overview of to the distribution sector

In Denmark, the distribution sector is concentrated, with the state owned DSO DONG Disttribution serving more than 90% of gas end customers. Competences for energy regulation in Denmark are split between the Danish Energy Regulatory Authority – Energistyrelsen- and the Danish Energy Agency.

1.1. Institutional structure and responsibilities

In Denmark there are 3 distributors. Data on total number of gas supplied customers is not available. Summary data on industry structure is set out below.

Table 111: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 customers	Exemption*	Share of total demand(DSOs <100,000 customers)
Country	3	0	3	2[60]	Yes	<10%
***accounting/functional only unbundling requirements for DSO with less than 100,000 customers.**						

The responsibility for setting distribution tariffs is spread between the following jurisdictions (for example):

- The DSO
- The NRA (The Danish Energy Regulatory Authority –DERA-)
- Government (Ministry of Climate, Energy and Building)

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

[60] CEER, Status Review on the Transposition of Unbundling Requirements for DSOs and Closed Distribution System
Operators, 2013.

Table 112: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges	Regulated services
DSO	Also involved	Calculates for NRA approval	Calculates for NRA approval	N/A
Government	Defines main principles	Defines main principles	Defines main principles	N/A
NRA	Calculates and approves	Approves methodology	Approves methodology	N/A

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adopted to setting distribution tariffs involves the following steps:

- The Ministry issues principles in the primary law.
- The regulator held a public hearing and issues a consultation paper on methodology.
- The regulator approves methodology for tariff structure proposed by the DSO.
- The DSO calculates the tariffs and reports these to regulator.

1.2. Key figures on revenue and tariffs

Distribution revenues in 2013 were DKR 1,500 million. No further split by service type or number of customers for each category is available.

2. Regulation of distribution activities

The distribution sector is regulated under a concession regime. An incentive-based form of regulation is applied with a revenue cap and benchmarking of operating expenditure.

2.1. General overview

The Danish Energy Regulatory Authority (DERA) regulates the Danish markets for electricity, natural gas and district heating. In the natural gas market, the regulation focuses on network companies. DERA also controls the prices and access conditions of the two Danish storage facilities. Finally, DERA sets the price for natural gas supplied by the natural gas companies with an obligation to supply.

The distribution sector is regulated under a concession regime. An incentive-based form of regulation is applied.

The distribution tariff is itemized separately to end-users.

Key features of the regulatory regime are set out in the following table

Table 113: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concessions are tendered for a period of 20 years.
Duration of tariff setting regime	4 years regulatory period. Allowed revenue is assessed annually and distribution tariffs are revised accordingly.
Form of determination (distributor propose/regulator decide)	Regulator approves methodology
Scope for appeal regulatory decision	DERA decisions can be appealed to the Energy Board of Appeal

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Revenues may depart from actual costs in order to provide incentives to reduce costs.
- Elements of output regulation: the regulator focus on costs based on the assumptions that the DSO will have to satisfy all the reasonable demands for service

At the same time the following tools are provided to mitigate risks:

- If DSOs do not set tariffs such that the revenue cap is fully utilised, the gap between income and revenue cap can be transferred to the following two years. That is, the allowed revenue in the following two years will increase in this case. On the other hand, if income exceeds tariffs by a certain amount of money, the DSO must pay back this amount by lowering tariffs over the following two years.
- If revenues fall short of the revenue cap, for instance because of a reduction in demand, the missing revenues can be recovered over the following years.
- DSOs are benchmarked against each other on operating costs. If however an extraordinary event occurs which forces extraordinary costs on the DSO in a particular year, the DSO can apply for an exemption of these costs from benchmarking.

There's no quality of service regulation implemented. However, technical standards on quality of service are set by the Danish Safety Technology Authority (Sikkerhedsstyrelsen).

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 114: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue Cap
Regulatory asset base	Book Value
Capital expenditure	N/A
Approach to operating expenditure	Benchmarking of operating costs. The results enters into the revenue cap. Benchmarking is based on a unit cost model.
Form of capital remuneration applied" (WACC real, nominal, ten years Treasury bond + adder, ...)	N/A
Additional revenue items (where applicable)	N/A

The following formula is applied in determining the WACC:

$$WACC = \frac{K_E}{1-t_e} \cdot \frac{E}{D+E} + K_D \frac{D}{D+E}$$

Where:

- KE = rf + β MRP is the cost of equity
- MRP is the Market RiskPremium
- KD is the cost of debt
- te is the corporate tax rate

The WACC is updated every fourth year ahead of a new regulatory period. Latest update was in 2013 counting for the regulatory period 2014-17.

The debt leverage is set by law.

3. Tariffs for distribution services

All consumers are charged only an energy-related (per m3) distribution tariff. There are 3 DSOs, each one charges different tariffs (corresponding to its allowed revenues). Small consumers pay a standard connection charges depending on the expected consumption. For larger consumers the connections charge is the part of the investment which is not covered by tariff payment within 3-5 years.

3.1. Distribution tariffs: additional issues

The DSO is in charge of setting the distribution tariffs (based on allowed revenues). All costs are recovered by an energy-related (per m3) distribution tariff. All consumers are charged only an energy-related (per m3) distribution tariff.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 115: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Yes the energy related component of the distribution tariff includes the cost of losses.
Presence of uniform tariffs	There are 3 DSOs, each one charges different tariffs (corresponding to its allowed revenues)
Presence of non-linear tariffs	The first m3 consumed in a year are more expensive, for higher consumption the unit tariff is lower.
Presence of regulated retail tariffs	Some suppliers have (through a tender) won a concession for an obligation to supply natural gas at a specific price (revenue cap) set by the tender. The obligation to supply is for a specific geographical area, and all consumers have the possibility to choose the obligation to supply product.
Presence of social tariffs	None

DSOs cost to generate energy savings is funded via an additional tariff component of the distribution tariff

3.2. Connection and capacity issues

Key issues in the setting of connection charges are set out in the table below.

Table 116: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Shallow charges for consumers and embedded generators
	Methodology adopted	Small consumers pay a standard connection charges depending on the expected consumption. For larger consumers the connections charge is the part of the investment which is not covered by tariff payment within 3-5 years. The difference must be paid up front. Very large consumers can choose between the model for large consumers or pay the whole installation cost up front – in return they get a reduced tariff over a ten year period.
Hosting capacity	Scope to refuse connection	In principle obligation to connect (subject to payment), but right to refuse access if • capacity not sufficient

	Issue	Approach
		• substantial economic or financial problems with take-or-pay-clauses, in which case DSOs can ask minister for a temporary derogation from obligation to give access.
	Requirements to publish hosting capacity	The DSO has a duty to map and publish the consumption of natural gas in the supply area.
	Targets and/or incentive schemes to enhance hosting capacity	None

4. Distribution system development and operation

4.1. Distribution system development

Distribution system development plans are not regulated. There is a provision in the Natural Gas Act which obliges DSOs and the TSO to connect installations for the upgrading of biogas in view of injection in the natural gas network. DSOs have full responsibility for metering, and own the meters.

The key features of distribution system planning are summarized below.

Table 117: Approach to distribution planning

Issue	Approach
Form of distribution planning document	
- Key responsibilities for its development	Distribution system development plans are not regulated.
- Degree of integration with environmental policies	There is a provision in the Natural Gas Act which obliges DSOs and the TSO to connect installations for the upgrading of biogas in view of injection in the natural gas network.
- Relationship with quality of service targets	None
- How trade-offs between network development and alternative technologies are treated	N/A
- Requirements to integrate cost benefit analysis	N/A

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 118: Key approach to metering

Issue	Approach adopted
DSOs role in metering	DSOs have full responsibility for metering, and own the meters.
Monopoly services in the metering	DSOs are monopolists in metering activities
Smart metering functionality	N/A

Country Report – Spain (electricity distribution)

1. Overview of to the distribution sector

There are 26 large scale electricity distributors in Spain; distributors with a customer base of less than 100.000 customers are responsible for supplying less than 5% of national electricity demand.

The Government has the main responsibility for setting the allowed revenues of DSOs; the regulator establishes the tariff structure.

1.1. Institutional structure and responsibilities

In Spain there are five large distributors supplying electricity to 29.5 million customers covering an area of 600.000 km^2. Summary data on industry structure is set out below.

Table 119: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 customers	Exemption*	Share of total demand
Country	342	N.a.	All	325	Yes, embedded generators pay a € 0.5 / MWh rate	Less than 5%

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**

The responsibility for setting the distribution tariff level is split between the Government (specifically, the Ministry of Industry, Energy and Tourism) and the Regulator. The Government (the Ministry of Industry, Energy and Tourism) is responsible for setting the methodology, setting the values and providing final approval of the allowed revenues (tariff levels). The regulator provides its opinion on the Ministry´s proposals.

In relation to the definition of the tariff structure, the regulator is responsible for setting the tariff structure. However, a draft amendment to the Electricity Act, which is still under parliamentary procedure, provides that the definition of the tariff structure will be assumed by the Ministry of Industry, Energy and Tourism. Connection charges are defined and set under the following approach: the regulator proposes, and the Ministry approves.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 120: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Not involved	Not involved	-
Government	Sets methodology, values and provides final approval	Not involved	Provides approval (or not) on NRA´s proposals
NRA	Provides opinion on Governments proposals	Sets the tariff structure (1)	Proposes the connection charges

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

(1) A draft amendment to the Electricity Act, which is still under parliamentary procedure, provides that the definition of the tariff structure will be assumed by the Ministry of Industry, Energy and Tourism.

1.2. Key figures on revenue and tariffs

Distribution revenues in Spain in 2013 were € 5070 million, broken down by the following activities:

- Distribution – € 4.906 million (y%), of which:
  - Revenues for DSOs with More than 100.000 customers: € 4.580 million
  - Revenues for DSOs with Less than 100.000 customers: € 325,2 million
- Quality of service - € 74.2 million
- Loss incentive – € 90.000

A breakdown of revenue by customer category, including information on the number of customers in each category is set out in the table below. It must be noted that typical customer categories (such as ´residential´, ´small industry´, etc.) are not used in Spain. Instead, customer tariff groups (customer classes) are generally based on the customer´s voltage connection. The final amount that each customer pays is based on two components: a per-kW charge (contracted power) and a per-kWh charge.

Table 121: Tariff components, customers and revenues per customer class

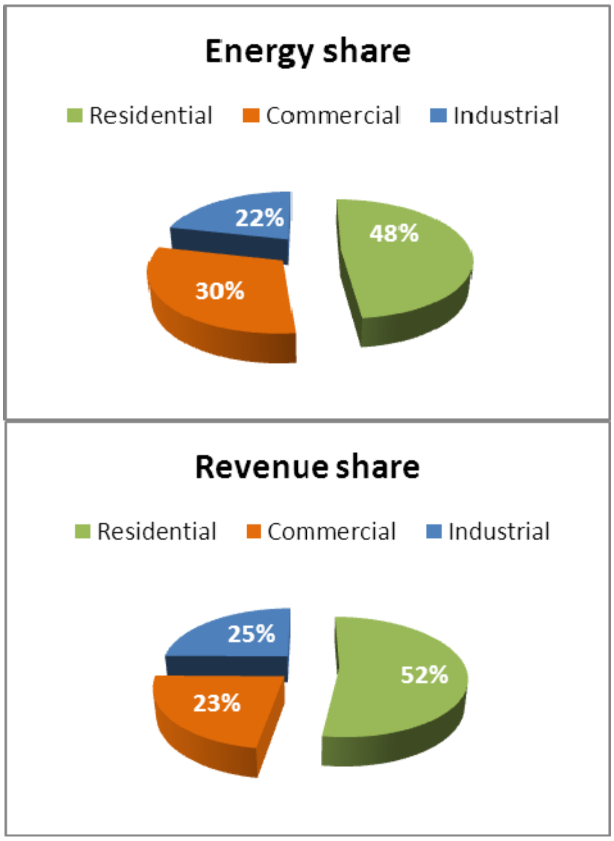
Voltage	Customer classes	Contracted power	Tariff components	Number of customers	Revenue
Low Voltage (< 1 kV)	2.0A	< 10 kW	KWh, KW	24848664	Not publicly-available
	2.0DHA		KWh, KW	1098107	Not publicly available
	2.0DHS		KWh, KW	1032	Not publicly available
	2.1A	>10 kW and < 15 kW	KWh, kW	686640	Not publicly available
	2.1DHA		KWh, kW	171844	Not publicly available
	2.1DHS		KWh, kW	15	Not publicly available
	3.0**A**	> 15 kW	KWh, kW	742267	Not publicly available
More than (or equal to) 1 kV and less than 36 kV	3.1A	< 450 kW	KWh, kW	83390	Not publicly available
	6.1A	> 450 kW	KWh, kW	19538	Not publicly available
More than (or equal to) 36 kV and less than 72,5 kV	AT2		KWh, kW	1604	Not publicly available
More than (or equal to) 36 kV and less than 72,5 kV	AT3		KWh, kW	423	Not publicly available
More than (or equal to) 145 kV	AT4		KWh, kW	546	Not publicly available
	Total		**-**	**26961043**	**Not publicly available**

Customers can be grouped based on the voltage level of their connection, as follows:

- Low voltage (< 1 kV) with contracted power less than 15 kW, includes groups 2.0A; 2.0DHA; 2.0DHS; 2.1A; 2.1DHA; 2.1DHS. This group can be considered as being roughly-equivalent to ´Household´;
  Low voltage (< 1 kV) with contracted power higher than 15 kW (3.0A) and More than (or equal to) 1 kV and less than 36 kV with contracted power less than 450 kW (3.1A): This group can be considered as being roughly-equivalent to ´Commercial´;
- More than (or equal to) 1 kV and less than 36 kV with contracted power higher than 450 kW: this group includes the 6.1A. This group can be considered as being roughly-equivalent to ´small industry´;
- More than (or equal to) 36 kV and less than 72,5 kV: this is AT2 customers, which are generally large industrial customers;
- More than (or equal to) 72,5 kV and less than 145 kV: this is AT3 customers, which are generally large industrial customers; and
- More than (or equal to) 145 kV: this is AT4 customers, which are generally large industrial customers.

The breakdown of energy volumes by customer category are set out in the charts below.

Figure 34: Proportion of energy accounted by customer categories



In general, the revenues received per customer category in 2013 were roughly in-line with the actual energy consumed per category. However, the revenue contribution of residential customers is slightly higher than that of industrial customers, based on the unit consumption of energy. Commercial customers provide a disproportionally low share of costs; that is, based on its actual energy consumption (30% of all consumption) its contribution to total revenues is low (23% of all allowed revenues).

2. Regulation of distribution activities

The distribution sector is regulated mainly under an incentive-based regime (based on reference unit investment costs and O&M costs).

The remuneration of the distribution activity provides incentives to increase the efficiency of the management, the economic and technical efficiency and the quality of the electricity supplied.

2.1. General overview

DSOs in Spain to provide feedback to the Government on its proposals for the allowed revenues; they also propose and apply connection charges. DSOs are also driven to improve the efficiency of their activities, through the use of incentives, and hence they are partly responsible for promoting competition in the retail markets.

The distribution sector is regulated mainly under an incentive-based regime (which considers reference unit investment costs and O&M costs).

The distribution tariff is bundled into an integrated tariff, which also includes the transmission tariff component; the overall tariff is known as the Access Tariff. The Access Tariffs also includes the transmission and distribution costs, but also, other cost like the removable premium scheme incentives, the nuclear moratorium, deficit of previous years, and non-peninsular compensation.

Key features of the regulatory regime are set out in the following table

Table 122: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	N.a.
Duration of tariff setting regime	Allowed revenues are assessed annually, and tariffs are review every three months
Form of determination (distributor propose/regulator decide)	The Government proposes and develops the methodology and allowed tariffs / revenues values; the regulator provides its opinion on the Government´s proposals
Scope for appeal regulatory decision	DSOs can appeal to the Court of Law

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Incentives to reduce the actual investment cost (compared to the unit investment cost);
- Incentives to reduce losses;
- O&M efficiency improvement incentives
- Quality of service; and
- Incentives for combating fraud.

No specific tools or mitigation measures are used to mitigate risks.

The remuneration of the distribution activity provides incentives to increase the efficiency of the management, the economic and technical efficiency and the quality of the electricity supplied. CNMC monitors compliance with quality of service standards in distribution through two main indexes, TIEPI and NIEPI, which measure, respectively, the time and number of supply interruptions (in terms of equivalent power interrupted). A DSO´s allowed revenues are increased (or decreased) if they perform better (or worse) than some predefined quality targets.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 123: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue-cap based with efficiency adjustments
Regulatory asset base	The unit investment costs used to determine investment values, and which determine the RAB, are updated yearly according to a methodology established by the regulator.
Capital expenditure	Allowed CAPEX is based on a comparison of unit investment costs plus incentives to reduce investment costs
Approach to operating expenditure	Incurred OPEX plus efficiency incentives
Form of WACC applied	The WACC formula is not currently applied in the calculation of allowed RoR. The allowed RoR is based on the Spanish 10-year bond plus 200 basis points

3. Tariffs for distribution services

In the allocation of costs between customer categories, distribution network costs and commercial service costs are both taken into account.

Tariffs are geographically uniform, linear and are not regulated.

Connection costs are shallow in nature, and are based on standard costs (but these can be challenged).

3.1. Distribution tariffs

In the allocation of costs between customer categories, the methodology established by the regulator (Circular 3/2014) considers two types of costs: distribution network costs and commercial service costs provided by the distributors.

The Distribution network costs methodology involves the:

- Breakdown of the distribution cost by voltage level;
- Breakdown of the distribution cost of each voltage level between cost associated with power and cost associated with energy;
- Breakdown of the distribution cost associated with power of each voltage level by time period. The cost associated with power of each time period is allocated to each tariff using a simplified network model; and
- Breakdown of the distribution cost associated with energy of each voltage level by time period. The cost associated with energy of each time period is allocated to each tariff using a simplified network model.

The Commercial service costs are distributed among tariffs depending on the number of consumers supplied under each tariff.

The tariff structure for each class of electricity consumers (excluding connection charges) includes that all tariffs have two components, a per kW charge (contracted power) and a per kWh charge. The available tariffs include:

Low Voltage (< 1 kV):

Contracted power < 15 kW

- *2.0TD* – 1 time period (energy and power)
- *2.02TD* – 2 energy time periods and 1 power time period
- *2.03TD* – 3 energy time periods and 1 power time period

Contracted power > 15 kW

- *3.0A* – 3 time periods (energy and power)

High Voltage (> 1 kV):

All tariffs have 6 time periods (energy and power)

- *6.1TD*: Voltage level 1 – 36 kV
- *6.2TD*: Voltage level 36 – 72.5 kV
- *6.3TD*: Voltage level 72.5 – 145 kV

Various other aspects of distribution tariff setting are summarized in the table below.

Table 124: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Not included as separate tariff component. The distribution losses, as the transmission losses, are part of the generation costs.
Presence of uniform tariffs	Yes
Presence of non-linear tariffs	No
Presence of regulated retail tariffs	No
Presence of social tariffs	Yes, social tariffs are available for consumers who meet certain criteria including: being a large family; a pensioner older than 60 years with a minimum pension; families where all members are unemployed; or low voltage consumers (less than 1 kV) with contracted demand lower than or equal to 3 kW.

As of 1st April 2014, “last resort tariffs” are only available to the following types of consumers, and in the following terms:

- Vulnerable consumers: in this case, the last resort tariff will be 25% lower than the PVPC; and
- Consumers that do not have the right to be supplied under the regime of voluntary price for small consumers, and do not have a free market supply contract in force. In this case, the last resort tariff will be 20% higher than the PVPC.

Embedded generators pay a transmission/distribution tariff of 0.5 €/MWh.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 125: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Shallow
	Methodology adopted	Standard costs (to determine the connection charges) are approved by the Ministry following the proposal of the NRA. The proposal is based on actual costs declared by the DSOs. For new supply points or the extension of existing points below 100 kW in LV and 250 kW in HV in urbanized areas, connection fees are established through regulation. For other situations, connection costs are computed on a case-by-case basis and paid by the applicant.
Hosting capacity	Scope to refuse connection	It may only refuse a connection if it lacks the required capacity to make the connection.
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	No

The DSOs are not required to notify the regulator of their hosting capacities. There is also no specific regulation which does not hamper investment and which implies additional OPEX (for example, smart grid technology, the use of demand side flexibility for grid services, etc.).

4. Distribution system development and operation

DSOs develop investment plans with 3-year horizons; these plans take into consideration consumption forecasts and quality of service targets.

DSOs are not permitted to dispatch renewable and flexible loads.

DSOs have full responsibility for metering activities and there are plans to roll out smart meters in the distribution sector in three time stages in the period out to 2018.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 126: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Investment plan looking 3 years ahead
- Key responsibilities for its development	Distribution Companies must submit their investment plans for the following 3 years to the Government and Regional Authorities for approval by 1 May of each year. The information is assessed by the regulator and there is a maximum level of investment established
- Degree of integration with renewables plan	No relation
- Relationship with consumption trends	The evolution of consumption in the distribution area is explicitly considered in the development plan
- Relationship with quality of service targets	Quality of service targets are explicitly taken as an input in the distribution development plan
- How trade-offs between network development and alternative technologies are treated	Not treated
- Requirements to integrate cost benefit analysis	No requirements; only general targets are included and integrated

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 127: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	Small and embedded renewable plants (such as domestic PV) are not dispatched. Larger embedded generators are dispatched, but not by the DSO. Rather, they are dispatched by the transmission system operator.
Possibility to dispatch flexible loads	No
Other sources of flexibility open to DSO	DSOs do have access to other sources of flexibility, such as batteries and capacitors

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 128: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs have full responsibility for metering
Monopoly services in the metering	DSOs are monopolists in metering
Smart metering functionality	Meters have the following functions: • Active Energy and Reactive Energy. • Maximum demanded power (15 ‘) • Hourly meter -> Capacity to store data

Issue	Approach adopted
	about 3 months. • Able to manage flexible tariffs: 6 Tariff Periods -> Capacity to store data for 3 bills. Registers have the following functions: • Quality Parameters • Events (alarms, changes in billing configuration, fraud detection, etc.) • Shows different information to user. Regarding power control, the following functionalities: • Power Limiter (contracted power) • Cut-off elements: inside or, at least, controlled by the meter • Manual or Automatic Reconnection

The rollout of smart meters in Spain is planned to be undertaken in stages, to the period up to the end of 2018. Specifically, the deadlines for the replacement of electricity metering systems for consumers with contracted power lower than 15 kW, and the installation of new intelligent metering systems able to provide time discrimination and remote control are:

a) Before 31th December 2014, 35% of all the meters of each distribution company shall be replaced with a smart meter. This is equivalent to around 10.000.000 smart meters.

b) Between January 1st, 2015 and December 31st, 2016, another 35% of all the meters of each distribution company shall be replaced with a smart meter.

c) Between January 1st, 2017 and December 31st, 2018, the final 30% of all the meters of each distribution company shall be replaced with a smart meter.

Data related to the numbers of smart meters currently installed per customer category is not available. Similarly, information on the cost- and energy-saving impacts resulting from roll out of smart meters to-date is not available.

Country Report – Spain (gas distribution)

1. Overview of to the distribution sector

There are four main large DSOs groups operating in Spain´s gas distribution sector, and of which 2 are ownership unbundled and the other 2 are legally unbundled. The share of total gas demand met by two DSOs which serve a customer base of 100000 or fewer is very limited.

The Government is the main entity responsible for deciding the level of allowed revenues; the NRA is responsible for proposingthe tariff structure. It must be noted, however, that the actual TPA tariff is bundled into a single tariff which includes the gas transmission tariff. The current TPA tariffs are published on the Spanish Official Botelin (BOE)

1.1. Institutional structure and responsibilities

In Spain there are 4 distribution groups supplying gas to 7448827 customers (in 2013). Summary data on industry structure is set out below.

Table 129: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	6 DSO groups (some of them have several affiliates, but under the same branch)	-2	All	2	No	Negligible
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

In the process of setting distribution tariffs the responsibilities of the involved parties is as follows. The Government (Ministry) issues the revenue calculation methodology and relevant principles in the primary law. It also calculates the allowed revenue and approves that amount. The regulator is involved in the process, insomuch as it is allowed to provide a non-binding opinion, which the Government can choose to take into consideration or not.

CNMC is currently developing the methodology to allocate the distribution costs to the tariffs. Until CNMC not approve this new methodology, the Ministry of Industry, Energy and Tourism will establish the distribution and transmission tariff. The methodology used by the Ministry is not publicly available.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 130: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Not involved	Not involved	Calculates and offers clients a quote, when pressure >4 bar. Not involved for clients connected with pressure <4 bar
Government	Defines main principals and calculates and proposes amounts	Not involved	Not involved
NRA	Can offer a non-binding opinion on the Government´s proposals	Sets the tariff structure	The Regional Authorities (not the NRA) may review a DSO´s price estimate if the client requests

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

1.2. Key figures on revenue and tariffs

Distribution revenues in Spain in 2013 were € 1.502.238 million; the breakdown of allowed revenues for each component activity is not published.

Moreover, it must be understood that in Spain, distribution tariffs are paid within a single tariff package which also includes the transmission tariffs. Indeed the two tariffs – distribution tariffs and transmission tariffs – are not separated: only the final tariff is published. Hence it is not possible to calculate the revenues allowed for distribution activities by individual customer categories. However, it is possible to define the various customer categories used and the tariff components (albeit without costs) within each customer category.

All tariffs paid by end-customers (which include both distribution and transmission tariffs) have two components:

- For consumers connected to a gas pipeline whose design pressure is higher than 4 bars (also including the tariff 3.5), the following charges apply: (1) a capacity-related charge, based on the contractual maximum daily withdrawal capacity, and (2) an energy-related component; and

- For consumers connected to a gas pipeline whose design pressure is less than or equal to 4 bars, (with the exception of the tariff 3.5), the following charges apply: a per-customer component and an energy-related component.

Group 1 - Consumers connected to a gas pipeline whose maximum design pressure is higher than 60 bars.

- **Tariff 1.1**: consumption less than or equal to 200,000,000 kWh/annum;
- **Tariff 1.2**: consumption of more than 200,000,000 kWh/annum and less than or equal to 1,000,000,000 kWh/annum; and
- **Tariff 1.3**: consumption of more than 1,000,000,000 kWh/annum.

Group 2 - Consumers connected to a gas pipeline whose design pressure is higher than 4 bars and lower than or equal to 60 bars

- **Tariff 2.1**: consumption less than or equal to 500000 kWh/annum;
- **Tariff 2.2**: consumption of more than 500000 kWh/annum and less than or equal to 5000000 kWh/annum;
- **Tariff 2.3**: consumption of more than 5000000 kWh/ annum and less than or equal to 30000000 kWh/annum;
- **Tariff 2.4**: consumption of more than 30000000 kWh/ annum and less than or equal to 100000000 kWh/annum;
- **Tariff 2.5**: consumption of more than 100000000 kWh/ annum and less than or equal to 500000000 kWh/annum; and
- **Tariff 2.6**: consumption of more than 500000000 kWh/ annum

Group 3 - Consumers connected to a gas pipeline whose design pressure is less than or equal to 4 bars

- **Tariff 3.1**: consumption less than or equal to 5000 kWh/annum;
- **Tariff 3.2**: consumption of more than 5000 kWh/annum and less than or equal to 50000 kWh/annum;
- **Tariff 3.3**.: consumption of more than 50000 kWh/annum and less than or equal to 100000 kWh/annum;
- **Tariff 3.4**: consumption of more than 100000 kWh/annum less than or equal to 8 GWh/annum; and
- **Tariff 3.5**: consumption of more than 8 GWh/annum

Group 4 - Industrial gas consumers which are interruptible.

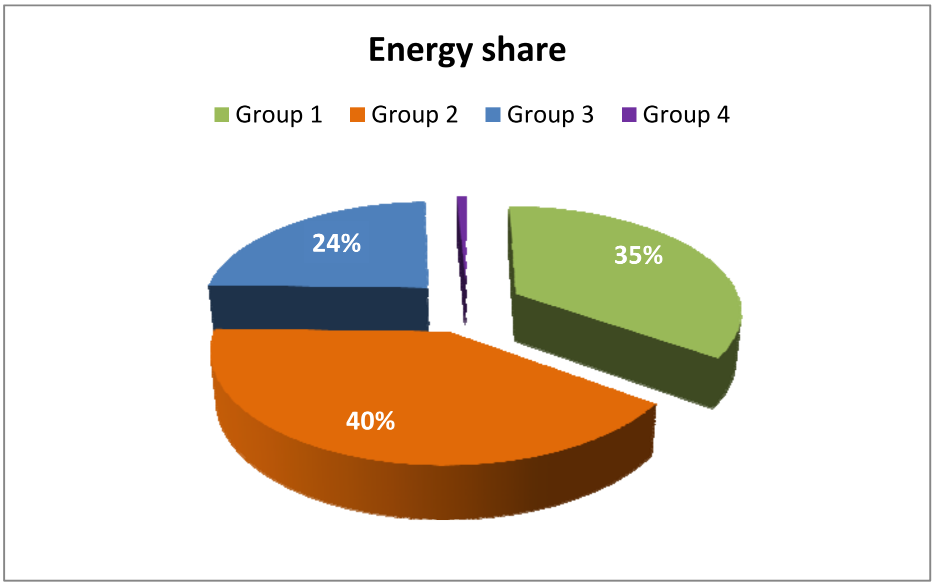
Table 131: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers (2013)	Revenue
Group 1	KWh; capacity charge	114	Data unavailable
Group 2	KWh; capacity charge	4108	Data unavailable
Group 3	kWh; customer component	7444598	Data unavailable
Group 4	kWh; customer	7	Data unavailable

	component		
Total	-	7448827	Data unavailable

The breakdown of energy volumes by customer category is set out in the chart below. Information concerning the breakdown of allowed revenues by customer category is not publicly-available.

Figure 35: Proportion of energy consumed by customer categories



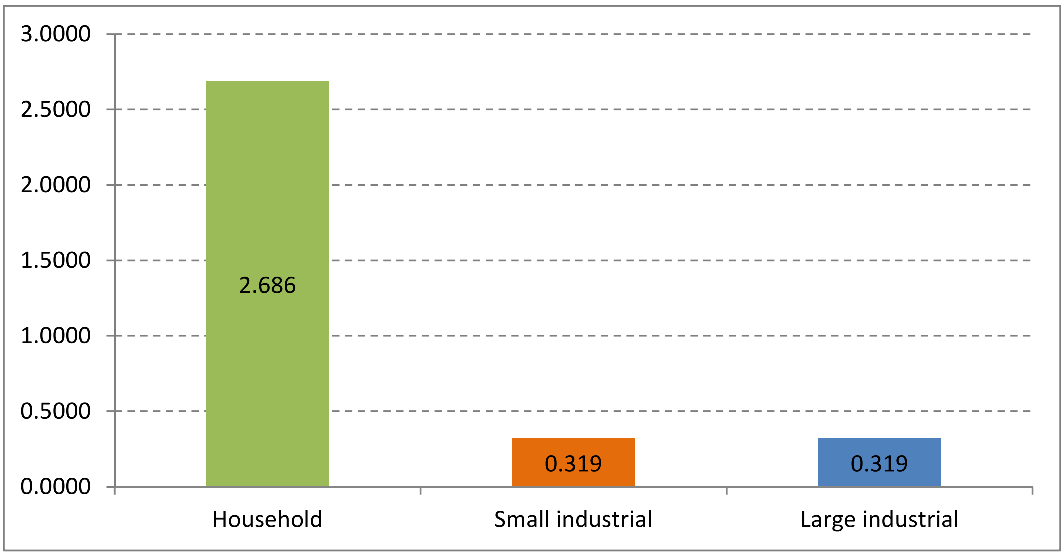
The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below. It must be noted that the tariffs include the costs applied for both distribution and transmission services. Tariffs for distribution and transmission services are applied as a single tariff in the Spanish gas sector and it is not possible to separate the two activities´ tariff components (because this is not published by the Government and is therefore not publicly-available).

Table 132: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Total
Residential (1) Tariff 3.2	15000kWh	81,15	321,69 2,1446 c€/kWh	403
Industrial and 7,000 use hours (Tariff 2.4)	50000000 kWh	104682	54800 0,1096 c€/kWh	159482
Industrial and 7,000 use hours (Tariff 2.4)	90000000 kWh	188428	98640 0,1096 c€/kWh	287068

The resulting average tariffs per kWh are illustrated below. Again, please note that these average charges include both the distribution and transmission tariff components.

Figure 36: Average network charges (€cents/kWh), 2013



2. Regulation of distribution activities

Distribution activities are regulated under a mixed regulatory regime, composed of cost reimbursement, an income Price cap and incentives. Performance incentives are based on energy delivered and the number of customers connected to the grid.

The regulator does not monitor DSOs´ planned investments, and DSOs do not require the regulator´s approval to make specific investments.

2.1. General overview

The role of DSOs in the Spanish gas sector is to deliver gas to customers as cost-efficiently as possible and also to promote the consumption of gas (switching from fuel consumption with higher levels of greenhouse gas emissions, or with a higher price or more inconvenient)) by increasing the numbers of gas grid-connected customers.

The distribution sector is regulated under a mixed regulatory regime which specifically includes:

- **Cost reimbursement:** Asset value and OPEX were first evaluated in 2002 in order to fix the allowed revenues; a **recent revision of allowed revenues was done in 2014**
- **Price cap:** After 2002, the allowed income was incremented every year by [0,85*Inflation index] plus the incentive; the yearly update by Inflation was removed from the methodology in 2014.
- **Incentive based (or output-based)** important incentives (positive o negative) according the evolution of 2 outputs:

- o Energy delivered through the distribution network; and
- o Number of consumers connected.

Key features of the regulatory regime are set out in the following table

Table 133: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	DSOs are subject to an authorisation regime (not concession regime) – authorisations do not have limited durations.
Duration of tariff setting regime	Tariffs are examined (and adjusted if necessary) every year
Form of determination (distributor propose/regulator decide)	Government proposes and decides; regulator is allowed to offer an opinion
Scope for appeal regulatory decision	None

2.2. Main incentive properties of the distribution regulatory model

DSOs are incentivised to reduce their costs because their allowed revenues are based on the energy supplied through their distribution network and the number of connected customers. This arrangement contrasts with a hypothetical situation where costs could be, for example, based on actual incurred costs: under such a regime, the DSO would not be incentivised to reduce its costs (because it would know that its costs would be reimbursed in any case).

There are no specific risk mitigation measures in effect in the Spanish gas distribution sector. The revenues are allowed to be adjusted at the end of the regulatory period, but there are no automatic adjustment mechanisms envisaged within the regulation.

By allowing that the changes in DSOs´ allowed revenue are based on two factors, namely the energy delivered through the distribution network, and the number of consumers connected to the network, DSOs should be incentivised to expand the gas grid to new consumers and new areas.

The regulator does not monitor DSOs´ planned investments, and DSOs do not require the regulator´s approval for making specific investments. This is because the output model ensures that DSOs should not make inefficient investments, because they would lose money on those (inefficient) investments.

Key components of quality of service regulation are that there are discounts in DSOs´ tariffs in the event of disruptions to the gas supply occurring, specifically:

- A 10% discount is allowed in compensation for gas interruptions of between 5 and 24 hours duration, and
- Progressive discounts are allowed in compensation for longer interruptions, and equivalent of up to 50% discount on the DSO tariff.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 134: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Price cap, with output-based incentives
Regulatory asset base	The RAB was first evaluated in 2002, and allowed initial income and then adjusted annually based on inflation, the increase/decrease in gas demand and changes in the number of customer connections. This method was then discontinued in 2014, and the Ministry adjusted the allowed income manually; however, the methodology used to adjust the allowed revenue is not publicly-disclosed.
Capital expenditure	Not specified / publicly-available
Approach to operating expenditure	Not specified / publicly-available
Form of WACC applied	Unknown

The WACC formula is not published by the Government in its calculations of allowed revenues and tariffs.

3. Tariffs for distribution services

The Government is responsible for establishing the level of allowed tariffs, and the regulator sets the tariff structure. Distribution tariffs are not published (or publicly-viewable); instead tariffs for distribution and combined with those of gas transmission, into a single tariff which end-users pay.

Connection charges are shallow in nature and based on standard costs.

3.1. Distribution tariffs

The methodology for the allocation of costs between customer categories is currently under review. CNMC, the Competition and Markets Commission, is currently developing the methodology to allocate the distribution costs to the tariffs. Once CNMC approves this new methodology the Ministry of Industry, Energy and Tourism will establish the distribution and transmission tariffs using a currently-unknown (not publicly-available) methodology.

The Ministry of Industry, Energy and Tourism publishes the distribution and transmission tariff structures and values in the Official Gazette.

Tariffs components are not differentiated based on the time of use, but there are multiplier factors, with a level between 1 and 3, for short term contracts.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 135: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Losses are settled between DSOs and retailers according to real losses, up to a 1% limit (over this limit, losses are covered by the DSO at their own expense)
Presence of uniform tariffs	Yes, they are uniform throughout the entire country
Presence of non-linear tariffs	No
Presence of regulated retail tariffs	Yes. For consumers connected to a gas pipeline whose design pressure is less than or equal to 4 bars and whose annual consumption is lower than or equal to 50,000 kWh/annum. Currently, around 30% of households in Spain are served under the regulated gas tariff
Presence of social tariffs	No

The Ministry of Industry, Energy and Tourism publishes the distribution and transmission tariff structures and values in the Official Gazette.

Tariffs components are not differentiated based on the time of use.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 136: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Shallow
	Methodology adopted	Standard costs are approved by the Ministry for the connection fees (for connections of up to 4 bar pressure). For high pressure pipeline connections, the DSO makes an estimate based on its cost but the client is free to procure the necessary works from a different source. In both cases (low and high pressure), the client can ask the Regional Authorities to set the price

		in the event that they do not agree with the DSO's estimate.
Hosting capacity	Scope to refuse connection	No
	Requirements to publish hosting capacity	DSOs are obliged to supply the gas system operator with a list of regional pipelines that are close to full capacity; it must do this on an annual basis. The system operator then publishes these lists.
	Targets and/or incentive schemes to enhance hosting capacity	Not specified

The DSOs are not required to notify the regulator of the technical capacity of their network.

Connection charges are composed of 2 different charges:

- Grid connection charges – €106/m per building/premises (the first 6 meters of the connection are free of charge) in low pressure pipeline connections; for pipeline connections of up to 4 bar, the DSO is required to develop its quote; and
- Customer connection charge – Around €200 per customer, including a full security check of the customer´s gas installation, installing the meter and open de-gas valve.

4. Distribution system development and operation

DSOs develop distribution planning documents once a year, and these are submitted to the local authority; they are not integrated with renewable plans or quality of service targets.

DSOs are fully responsible for providing metering services, and are monopolists.

The rollout of smart meters in the Spanish gas distribution segment has not been successful in the past. There are no specific plans to rollout smart meters in the near term future; indeed a decision has been taken not to pursue the rollout of smart meters in the distribution sector.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 137: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Annual planning document describing the plans for developing the gas distribution grid
- Key responsibilities for its development	DSOs develop the plans and submit them to the local governments/authorities, each year
- Degree of integration with renewables plan	N.a.

- Relationship with consumption trends	Not specifically addressed
- Relationship with quality of service targets	No relationship
- How trade-offs between network development and alternative technologies are treated	The Spanish National Competition and Markets Commission (CNMC) undertook a Cost Benefit Analysis for the introduction of gas smart meters in Spain. The CNMC found that the CBA result was overall negative and has therefore recommended not to include any obligation of introducing smart meters in the gas distribution sector in Spain
- Requirements to integrate cost benefit analysis	No strict requirements to integrate; however, the CBA results are public and have been shared with the regulator

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 138: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs have full responsibility for metering, and they own the majority of household meters: meters are rented to gas customers, but customers can also buy their own meters. Industrial customers usually own their own meters.
Monopoly services in the metering	Yes
Smart metering functionality	Not applicable, because smart meters have basically not been deployed to gas consumers in Spain.

The rollout of smart meters in Spain has neither been successful in the past nor are there plans to do so in the near term future.

A Cost Benefit Analysis (undertaken by the Competition and Markets Commission) of the scope for rolling out smart meters returned a negative overall result; hence, Spain decided to not obligate to roll out smart meters for gas customers.

The cost benefit analysis was undertaken taking into consideration optimal future development assumptions of smart meter systems, as well as costs taken from smart meter CBAs in France and Great Britain.

At the current time, around 4.000 large customers have meter systems installed which are capable of daily measurements, covering 80% of gas demand. There is no obligation for smart meters to be installed for the approximately 7,5 million small customers in the country.

Country Report – Finland (electricity distribution)

1. Overview of to the distribution sector

There are 80 DSOs operating in Finland, supplying power to some 3,1 million customers.

DSOs set their own tariffs (including deciding on the structure of those tariffs) for consumers.

1.1. Institutional structure and responsibilities

Finland's 15 largest electricity network companies are responsible for around 70% of the distribution networks. The smallest electricity network companies in Finland operate within the area of a single municipality, serving a few thousand customers.[61] In Finland there are 81 distributors supplying electricity to 3,1 million customers. The majority of the DSOs are owned by municipalities or are listed companies controlled by the relevant municipality. Summary data on industry structure is set out below.

Table 139: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 customers	Exemption*	Share of total demand
Finland	81	-	52	73	No	Approx.80 %
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

The responsibility for setting distribution tariffs is held by the DSO only.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

[61] Energy Market Authority, Key figures for electricity system operations in 2011

Table 140: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Calculates the tariffs	Sets the tariff levels	Sets the charges
Government	Proposes the primary law to the Parliament	Not involved	Not involved
NRA	Issues the methodology for the revenue cap	Not involved	Sets the methodology for the connection charges

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adopted to setting distribution tariffs is such that the Government develops the primary law which will guide the process, and based on this the NRA issues the methodology to be used in calculating the revenue cap. Following this methodology, the DSOs then calculate the tariffs to be offered to customers. In terms of deciding the structure of the tariffs, the DSO has full responsibility and neither the NRA nor the Government are involved.

If a DSO is considering affecting a price change, it is required to notify the Energy Authority. However, it is not necessary to undertake a public consultation on any proposed price change.

1.2. Key figures on revenue and tariffs

Distribution revenues in Finland in 2013 were € 1.550 million. The breakdown of allowed revenues to specific regulated activities is not publicly-available.

Information on the available tariff components of each customer class is set out in the table below. Information on the amounts of allowed revenues received, per customer class, is not publicly-available, and the Finnish NRA does not have that data.

Table 141: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Revenue
Residential	KWh, kW, kVA	Not available
Farming	KWh, kW, kVA	Not available
Small industry	KWh, kW, kVA	Not available
Mid-sized industry	KWh, kW, kVA	Not available
Total	-	Not available

The specific customer categories used for setting individual tariffs, are further broken down from the tariff categories shown in the table above, and are defined as follows:

- K1. A flat without sauna, main fuse 1x25 A, usage 2 000 kWh/annum
- K2. Small house or apartment, with sauna, no electrical heating, main fuse 3x25 A, usage 5000 kWh/annum
- M1. Farm, no electrical heating, main fuse 3x35 A, usage 10000 kWh/annum

- M2. Farm with live stock breeding, electrical heating, main fuse 3x35 A, usage 35000 kWh/annum
- L1. House with electrical heating in every room,3x25 A, usage 18000 kWh/annum
- L2. House with a partially storing electrical heating system, main fuse 3x25 A, usage 20000 kWh/annum
- T1. Small industry, usage 150000 kWh/annum, peak power, 75 kW
- T2. Small industry 600000 kWh/annum, peak power 200 kW
- T3. Middle size industry, usage 2000000 kWh/annum, peak power 500 kW
- T4. Middle size industry, usage 10000000 kWh/annum, peak power 2500 kW

Customer categories K1, K2, L1, L2, M1, M2, T1 and T2 are assumed to be connected to the 0,4 kV network, and T3 and T4 are assumed to be connected to the 20 kV network.

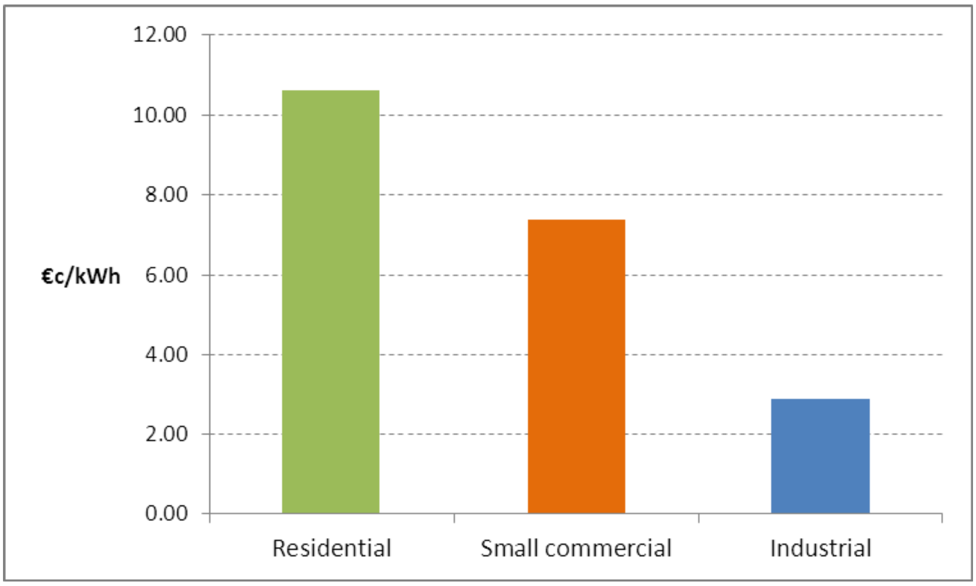
The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below:

Table 142: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Demand and reactive charges	Total
Residential	3500kWh	163	209	-	372
Small commercial	50MWh	67	1941	1686	3694
Industrial	24000MWh	67	643920	56046	700033

The resulting average tariffs per kWh are illustrated below.

Figure 37: Average network charges (€cents/kWh), 2013



2. Regulation of distribution activities

DSOs design and set their own tariffs, and all tariff components must correspond to specific distribution cost components. Incentives are applied as follows: Investment incentive; Innovation incentive; Efficiency incentive; Quality incentive; and a Security of supply incentive.

2.1. General overview

The role of the DSOs in Finland is to set the distribution grid tariffs, and hence promote retail market competition through providing customer choice of distribution service provider. Neither the Government nor the NRA is involved in setting the actual distribution tariffs. The distribution sector is regulated under an incentive-based regulatory regime.

Projects which are developed by DSOs require a license in order to be built.

All components within the distribution tariffs correspond to specific distribution cost factors.

Lastly, in the case of embedded generators they pay distribution tariffs (which are equivalent to transportation tariffs), but the fee is lower than those levied for standard customers.

Key features of the regulatory regime are set out in the following table.

Table 143: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	License
Duration of tariff setting regime	Allowed revenues are assessed for a 4-year horizon, but some parameters are updated annually. Distribution tariffs are set independently by the DSOs
Form of determination (distributor propose/regulator decide)	DSO sets the tariffs
Scope for appeal regulatory decision	N.a.

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Investment incentive
- Innovation incentive
- Efficiency incentive
- Quality incentive
- Security of supply incentive

At the same time the following tools are provided to mitigate risks:

- Volume risk. According to the current legislation, if revenue target is exceeded over the regulatory period of four years, the DSO has to take it into account when deciding tariffs in the following regulatory period. However, if the target is not met and the DSO has revenues to be recovered after the regulatory period, then the DSO has a possibility to recover them within the next regulatory period, but no obligation to do so.

  Some of the volume risk is covered in the efficiency incentive due to the fact that network expansion and number of customers is updated annually.

- No other specific forms of risk mitigation measures are in effect in Finland, but a DSO can apply for a methodology amendment under exceptional circumstances.

The quality of the service incentive is based on the cost of interruptions to the customer. The quality of service regulation interacts with the tariff system in that allowed revenues are increased (or decreased) if the DSO performs better (or worse) than in its predefined quality targets. Revenues can increase or decrease up to a level which is equivalent to 20% of the annual rate of return (€). For example, 20% in 2014 means 60 basis points in the WACC calculation.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 144: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue based with performance incentives
Regulatory asset base	Efficient investment included in the RAB and reconciliation mechanisms are used to ensure that actual revenues are in-line with allowed revenues
Capital expenditure	Incentive-based
Approach to operating expenditure	Incentive-based
Form of WACC applied	Real reasonable rate of return, after corporate tax

The following formula is applied in determining the WACC:

$$R_{k,post-tax} = WACC_{post-tax} \times (D+E)$$

where

$R_{k,post-tax}$ = weighted average cost of capital, i.e. real reasonable rate of return after corporate tax, in euros

$WACC_{post-tax}$ = real reasonable rate of return after corporate tax

D = adjusted amount of interest-bearing debt, in euros

E = adjusted amount of equity, in euros

$D+E$ = adjusted capital invested in the DSO's network operations, in euros

$$\text{WACC}_{post-tax} = C_E \times \frac{E}{D+E} + C_D \times (1-t) \times \frac{D}{D+E}$$

where

$WACC_{post-tax}$ = weighted average cost of capital, i.e. real reasonable rate of return after corporate tax

C_E = cost of equity

C_D = cost of interest-bearing debt

t = rate of corporate tax during the period under review

D = amount of interest-bearing debt

E = amount of equity

3. Tariffs for distribution services

Shallow and deep connection charges can be used for connection charges. Standard costs are approved by the regulator.

There are no specific targets or incentive schemes in use to encourage DSOs to enhance their hosting capacities and DSOs are assumed to have a duty to connect all the renewable capacity that applies for connection.

3.1. Distribution tariffs

The methodologies used to allocate distribution costs to tariffs vary considerably between the different DSOs.

However, the tariff structure for the different classes of electricity consumers is that:

- LV customers´ tariffs vary and tariff structures include both KW and KWh parts.
- For larger LV customers there are possibilities to choose time-of-use tariffs based on day and night time of use or winter and summer time of use.
- MV customers´ tariffs are mainly based on a KW charge.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 145: Approach to key issues in setting distribution tariffs

Issue	Approach

Treatment of distribution losses	Charged within the tariffs
Presence of uniform tariffs	No
Presence of non-linear tariffs	No, they are all linear
Presence of regulated retail tariffs	No
Presence of social tariffs	No

If a DSO uses special incentives in their network tariffs, for example for large consumers such as power plants, it must offer those same incentives it to all plants under equal terms and conditions.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 146: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Both. Shallow charges for small consumers and small embedded generators. Deep charges for larger consumers and generators
	Methodology adopted	Standard costs are approved by the regulator for both uniform and client-specific connection fees. For larger consumers or generators the DSO makes an estimate based on its costs, but the client can ask the regulator to set the price in case he does not agree with the DSO's estimate.
Hosting capacity	Scope to refuse connection	Not allowed to refuse connection
	Requirements to publish hosting capacity	No requirement
	Targets and/or incentive schemes to enhance hosting capacity	None

Shallow connection charges are used for small consumers and small embedded generators. In contrast, deep charges are used for larger consumers and generators: this includes the costs of new infrastructures at the same voltage level and the costs of the reinforcement of networks at the voltage level immediately above.

There are no specific targets or incentive schemes in use to encourage DSOs to enhance their hosting capacities. The DSO is assumed to have a duty to connect all the renewable capacity that applies for connection.

4. Distribution system development and operation

DSOs develop their respective distribution planning documents, which are provided to the regulator, every 2 years.

Flexible loads are all only controlled by the system operator or self-dispatched (i.e. are not dispatched by the DSO).

DSOs are fully responsible for metering and in 2013 around 93% of all consumers had a smart meter installed and operating.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 147: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Distribution network development plans are notified to the regulator. The documents are not published.
- Key responsibilities for its development	DSOs develop the plans every 2 years
- Degree of integration with renewables plan	Not integrated or connection with renewable targets/plans
- Relationship with consumption trends	No connection
- Relationship with quality of service targets	Quality of service targets are explicitly taken as an input in the distribution development plan and the plan illustrates the relation between the investments and the quality objectives in the distribution area.
- How trade-offs between network development and alternative technologies are treated	No particular treatment specified
- Requirements to integrate cost benefit analysis	Not required. The plan only reports the decisions taken by the DSOs

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 148: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	Smaller embedded generators (like residential PV) are not dispatched but larger embedded generators are dispatched by the system operator (not by the DSO)
Possibility to dispatch flexible loads	Flexible loads are all only controlled by the system operator or self-dispatched
Other sources of flexibility open to DSO	No other sources

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 149: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs have full responsibility for metering, and they own the meters in most cases (some have leasing contracts).
Monopoly services in the metering	DSOs are monopolists in metering activities
Smart metering functionality	Remote reading Remote disconnection and reconnection of customers

As of 2013 there were 3,1 million smart meters installed (up to fuse size 63A) in Finland. This is equivalent to 93% of all customers.

There are no approved plans to further deploy smart meters, but the final target is near about 100 % of the DSOs´ customers.

The impacts of the roll out of smart meters in Finland was initially planned to be analysed through the use of a cost-benefit-analysis tool (available for use by the major Finnish utilities) as well as the collection of feedback on smart meter impacts. However, the decision was taken in 2009 to rapidly-roll out smart meters to the overwhelming majority of electricity customers in the country, and this aim was largely achieved (only 7% of customers did not have a smart meter in 2013) in a short period of time. Consequently, the NRA reported that the cost-benefit tool became less necessary as a decision support tool for monitoring the roll out process. It is understood that specific information on energy consumption reductions (following smart meter installations) and monetary savings per household, for example, are neither currently publicly-available nor used by the Finnish NRA.

Country Report – Finland (gas distribution)

1. Overview of to the distribution sector

There are 25 DSOs operating in the Finnish gas sector, each of which serves an individual customer base of less than 100000 customers.

The NRA is responsible for setting the level of allowed revenues and individual DSOs are responsible for setting their own tariff structures to be offered to customers.

1.1. Institutional structure and responsibilities

In Finland there are 25 distributors supplying gas to 75742 customers with a gas distribution network length of 1959 km. Summary data on industry structure is set out below.

Table 150: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Finland	25	N.a.	N.a.	25	N.a.	100%
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

It should be noted that all Finnish DSOs fall below the size requirements for being required to implement legal and ownership unbundling requirements, as set by the Natural Gas Market Directives. That is, all Finnish DSOs have fewer than 100000 customers each. All Finnish DSO are required to, and have implemented, account unbundling.

The responsibility for setting the allowed revenues (distribution tariffs) in Finland is held by the NRA. Allowed revenues are assessed in every four years, but some of the parameters are updated annually. Investments by DSOs are not subject to any form of ex ante approval by the NRA. A partial ex post assessment of the usefulness of DSOs´ investments is carried out by the NRA, but it is not published.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 151: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO		Sets the tariff structure	Calculates (on a case-by-case basis)
Government			
NRA	Sets the revenue cap		Approves (or not) the costs calculated by the DSOs

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

Individual DSOs set the tariff structures of the tariffs they offer to customers.

1.2. Key figures on revenue and tariffs

Distribution revenues in Finland in 2013 were € 72 million. The proportions of allowed revenues per regulated activity (e.g. metering, distribution, customer management) are not published.

The gas distribution sector is fully liberalised and each DSO sets its own tariff structures. Information is not publicly-available on the revenues received from each customer class, and the energy consumption of each customer class. The NRA is unable to provide this information.

The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below:

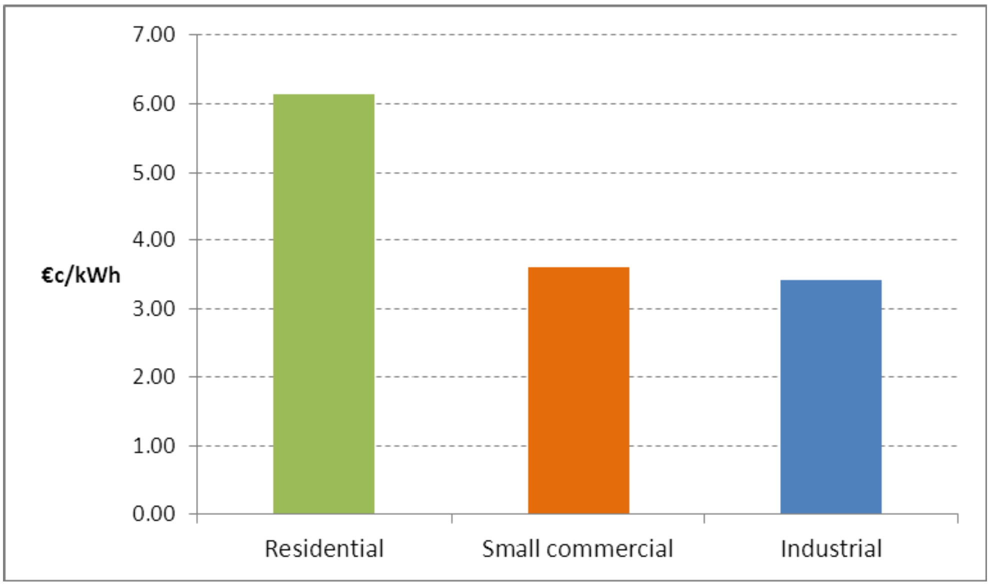
Table 152: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Demand and reactive charges	Total
Residential	15000kWh	Included, varies depending on the DSO	Included, varies depending on the DSO	Not included	Varies depending on the DSO
Small commercial	50000000 kWh	Included, varies depending on the DSO	Included, varies depending on the DSO	Not included	Varies depending on the DSO
Industrial	90000000 kWh	Included, varies depending on the DSO	Included, varies depending on the DSO	Included, varies depending on the DSO	Varies depending on the DSO

Distribution tariffs are itemised separately (i.e. are not bundled into an integrated retail tariff) for end-users. Tariffs vary significantly between DSOs

The average tariffs per kWh for a small municipal-level DSO are shown below. These values should be considered as an example only.

Figure 38: Average network charges (€cents/kWh), 2013



2. Regulation of distribution activities

The regulatory regime is based on cost plus, and an incentive mechanism.

A revenue adjustment mechanism is in place and can be applied in the event that revenues are substantially different from previously-planned values. There is no quality of service incentive.

2.1. General overview

The distribution sector is regulated under a cost plus regime with an incentive-based component.

Key features of the regulatory regime are set out in the following table

Table 153: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	License
Duration of tariff setting regime	4 years
Form of determination (distributor propose/regulator decide)	The regulator sets the methodology for the revenue cap but distribution tariffs are set by the DSO independently.
Scope for appeal regulatory decision	DSOs can appeal to the Market Court on regulatory decisions on allowed revenues.

2.2. Main incentive properties of the distribution regulatory model

An investment incentive is used within the regulatory model for the DSOs.

At the same time the following tools are provided to mitigate risks:

- According to the current legislation, if revenue target is exceeded over the regulatory period of four years, the DSO has to take it into account when deciding tariffs in the following regulatory period. However, if the target is not met and the DSO has revenues to be recovered after the regulatory period, then the DSO has a possibility to recover them within the next regulatory period, but no obligation to do so.
- DSOs can also apply for a methodology amendment (to the regulatory model) due to exceptional events.

No quality of service regulation is in effect in Finland.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 154: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Cost plus
Regulatory asset base	Efficient investments included in the allowed RAB, with ex-post adjustments if necessary
Capital expenditure	Cost plus, no benchmarking
Approach to operating expenditure	Cost plus, no benchmarking
Form of WACC applied	Real reasonable rate of return after corporate tax

The following formula is applied in determining the WACC:

$$R_{k,post-tax} = WACC_{post-tax} \times (D + E)$$

Where:

$R_{k,post-tax}$ = weighted average cost of capital, i.e. real reasonable rate of return after corporate tax, in euros

$WACC_{post-tax}$ = real reasonable rate of return after corporate tax

D = adjusted amount of interest-bearing debt, in euros

E = adjusted amount of equity, in euros

$D+E$ = adjusted capital invested in the DSO's network operations, in euros

$$\mathrm{WACC}_{post-tax} = C_E \times \frac{E}{D+E} + C_D \times (1-t) \times \frac{D}{D+E}$$

Where:

$WACC_{post-tax}$ = weighted average cost of capital, i.e. real reasonable rate of return after corporate tax

C_E = cost of equity

C_D = cost of interest-bearing debt

t = rate of corporate tax during the period under review

D = amount of interest-bearing debt

E = amount of equity

The financial structure in the WACC formula reflects the average financial structure of all DSOs. Current debt/equity ratio is 70/30 for DSOs.

3. Tariffs for distribution services

DSOs design and implement their preferred tariffs. DSOs are obliged to publish all the tariffs they offer.

Connection charges are shallow in nature and DSOs are obliged to inform the regulator of the hosting capacity of their networks.

3.1. Distribution tariffs

There is no single approach used by DSOs to allocate distribution costs to the tariffs. DSOs have the freedom to use the approach they prefer. DSOs are in charge of setting the distribution tariffs.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 155: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included as a part of the distribution tariffs
Presence of uniform tariffs	No
Presence of non-linear tariffs	Yes
Presence of regulated retail tariffs	No
Presence of social tariffs	No

Distribution tariffs are published, and indeed every DSO has an obligation to publish every distribution tariff they offer to customers.

There are no aspects included within the distribution tariffs which do not correspond to distribution costs. Tariff components are not differentiated according to the time-of-use.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 156: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Shallow
	Methodology adopted	For residential and for residential customers there is case-by-case pricing, but connection fees are not set by regulator. For larger consumers and generators connection costs are also computed on a case-by-case basis.
Hosting capacity	Scope to refuse connection	DSOs are not allowed to refuse connections for consumers and generators
	Requirements to publish hosting capacity	No requirement
	Targets and/or incentive schemes to enhance hosting capacity	N.a.

The DSOs are not required to notify the regulator of the hosting capacity of their individual networks.

4. Distribution system development and operation

DSOs are not required to develop and publish planning documents.
DSOs are fully responsible for, and are monopolists, of metering activities.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 157: Approach to distribution planning

Issue	Approach
Form of distribution planning document	None – network development plans are neither notified to the regulator nor published
- Key responsibilities for its development	N.a.
- Degree of integration with renewables plan	N.a.
- Relationship with consumption trends	N.a.
- Relationship with quality of service targets	No relationship
- How trade-offs between network development and alternative technologies are treated	None
- Requirements to integrate cost benefit analysis	None

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 158: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	N.a.
Possibility to dispatch flexible loads	N.a.
Other sources of flexibility open to DSO	N.a.

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 159: Key approach to metering

Issue	Approach adopted
Discos role in metering	Full responsibility for metering activities, and they own the meters
Monopoly services in the metering	Yes, DSOs are monopolists in metering activities
Smart metering functionality	Not specified

Almost all gas customers in Finland are standard (non-smart meter) metered customers. Specifically, only one DSO has installed smart meters, which, according to the NRA, altogether totalled a few thousand customers. No information is available on the impacts on those smart meter installations (such as, for example, the electricity consumption reduction achieved or the average household cost saving).

Country Report – France (electricity distribution)

1. Overview of the distribution sector

In France the distribution sector is rather concentrated, with ERDF representing around 95% of the distribution network. The sector is regulated. The DSO has a rather limited role in setting the allowed revenue and the distribution tariffs. The government retains the power to revert ask the NRA to revise its deliberations if it considers that its general policy orientations have been disregarded.

1.1. Institutional structure and responsibilities

In *France* there are around 160 distributors supplying electricity to approximately 35 million of customers with an overall circuit length of 1293466 km[62]. Summary data on industry structure is set out below.

Table 160: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	148[63]		5	143	Yes	< 5%
*** Embedded generators do not pay any distribution tariffs.**						

The responsibility for setting distribution tariffs is spread between the following jurisdictions:

- The DSO
- The NRA (Commission de régulation de l'énergie-CRE) regulates the electricity and gas networks guaranteeing the right of access to public electricity grids and natural gas networks and facilities, ensuring the proper functioning and development of electricity and liquefied natural gas networks and infrastructure, ensuring the independence of system operators and contributing to building the European Internal Market for electricity and gas. It also regulates the electricity and gas markets monitoring transactions on the electricity, natural gas and CO2 markets, ensuring the proper functioning of retail markets, contributing to the implementation of measures to

[62] Eurelectric, Power Distribution in Europe – Facts & Figures, 2013.
[63] CEER, Status Review on the Transposition of Unbundling Requirements for DSOs and Closed Distribution System
Operators, 2013.

support electricity generation and supply of electricity and gas and informing all consumers)

- Government (Ministère de l'écologie, du développement durable et de l'énergie)

The breakdown of responsibilities as related to tariff setting is summarized in the table below.

Table 161: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Sends accounting and financial data to NRA		Calculates for NRA approval
Government	Defines main principles, can ask the NRA for a new deliberation	Defines main principles	Defines main principles, sets rules[64]
NRA	X	X	X

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adopted to setting distribution tariffs involves the following steps:

- the Government elaborates general policy orientations;
- the methodologies used to establish tariffs for the use of public electricity transmission and distribution grids are set by the CRE;
- the DSO sends to the CRE its business plan, including justification for the planned costs level in order to allow the regulator to fix/modify the distribution tariff levels; the financial and accounting document are sent for ex-post adjustments on non-controllable items
- The CRE takes into account the energy policy guidelines indicated by the Government and it regularly informs the Government during the tariff establishment phase;
- The CRE consults energy market stakeholders as it sees fit[65];
- The CRE transmits to Government, for publication in the *Journal Officiel de la République Française* its reasoned decisions on changes in the level and structure of distribution tariffs;
- In the following two months, the Government can ask the CRE for a new deliberation if it believes the CRE has not taken in due account the governmental general principles adopted in the domain of energy policy.

1.2. Key figures on revenue and tariffs

Distribution revenues in 2013 were € 12496,8 million. No further split by service type is available.

[64] Precise charging perimeters are specified by decree; costs estimates and charging methodology is set forth by a decree proposed by the regulator and enacted by the Minister of energy.
[65] In the last case, the regulator issued 5 consultations papers and held public hearings.

Users are differentiated by their voltage level.

For a given voltage level, the user (or supplier for him) is free to choose the distribution tariff he wants. All users face a similar tariff structure, but values change depending on the voltage level and the tariff chosen. Each tariff consists of:

- A fixed component reflecting the cost of administrative management and metering. This latest component depends on the ownership regime of the metering system.
- A per kW component, which could be time differentiated, based on the contractual power ;
- A per kWh component, which could be time differentiated, based on actual withdrawals from the grid.

A breakdown of revenue by customer category and the number of customers in each category is set out in the table below.

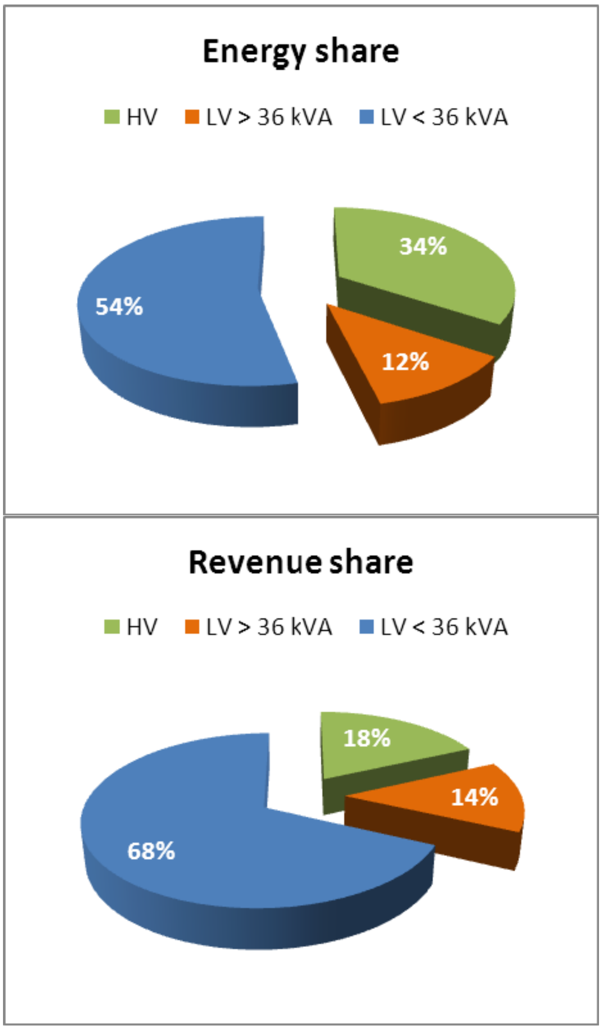
Table 162: Tariff components, customers and revenues per customer class

Customer classes	Number of customers[66]	Revenue (M€)
HV	Around 94000	About 2000
LV > 36 kVA	Around 370000	About 1500
LV < 36 kVA	Around 34000000	About 7500
Total	Around 35000000	About 11000

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

[66] CRE forecast 2013.

Figure 39: Proportion of energy[67] and revenue accounted by customer categories



The typical network tariff in 2014 for residential, small and large industrial customers is illustrated below[68]:

Table 163: Breakdown of annual charges – typical customer types, 2014 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Metering charges	Load and reactive charges	Total
Residential[69]	3500kWh	8,9	120,8	18,8	21,6	170,1
Small	50MWh	68,9	1298	398	475	2239,9

[67] CRE forecast 2013.

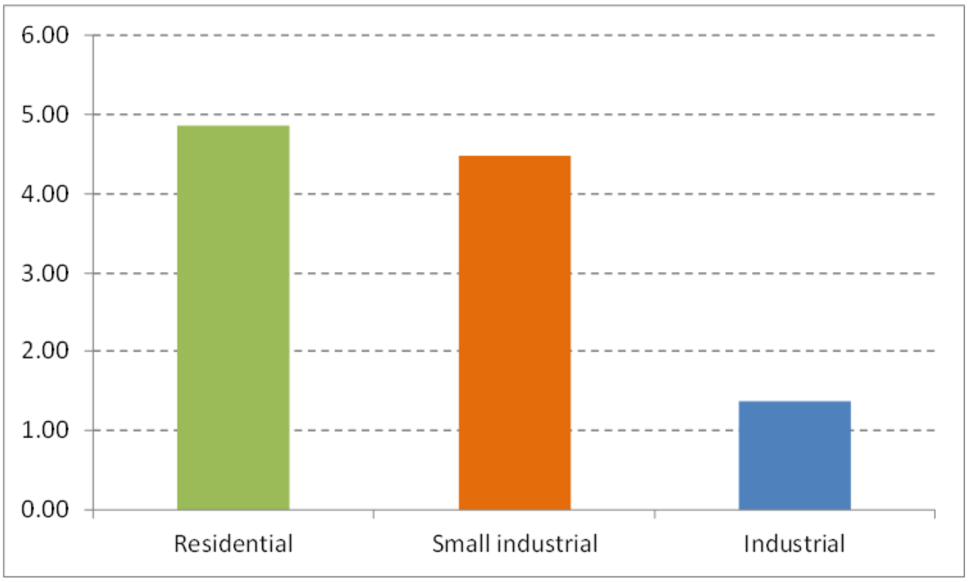
[68] REF-E estimates based on ERDF tariffs in 2014 and CRE hypotheses.

[69] CRE hypothesis: voltage level LV < 36 kVA, base tariff (no temporal differentiation), power contracted 6kV, usual metering system (for the metering component: power control through circuit breaker, variables measured through index, user is not the owner of the metering system; for the administrative management component: user has only one contract with his supplier - no direct contract with the DSO-).

industrial[70]						
Industrial[71]	24000MWh	68,9	252896,3	1206,5	74106	328277,7

The typical network average tariffs in 2014 per kWh are illustrated below.

Figure 40: Average network charges (€cent/kWh), 2014



An example of network tariffs applied in 2014, by ERDF is available at the following link: http://www.erdf.fr/medias/Institutionnel/TURPE_4_Plaquette.pdf .

2. Regulation of distribution activities

2.1. General overview

The role of the DSO in France is to define and to do the necessary investments in order to connect users to the grid it manages, respecting the environment and ensuring energy efficiency. It has a duty to report every year to the local administrations (which own the gas distribution network) the state of the infrastructure developments. The

[70] CRE hypothesis: voltage level LV > 36 kVA, Medium Usage, power contracted 40kV, usual metering system (for the metering component: power control through overshoot, variables measured through measurement curve, user is not the owner of the metering system; for the administrative management component: user has only one contract with his supplier - no direct contract with the DSO-)

[71] CRE hypothesis: voltage level HVA, base tariff (no temporal differentiation), power contracted 3,450kV, usual metering system (for the metering component: power control through overshoot, variables measured through measurement curve, user is not the owner of the metering system; for the administrative management component: user has only one contract with his supplier - no direct contract with the DSO-).

DSO stipulates and manages the concession with the local administration and ensures transparent, objective and non-discriminatory access conditions to the gas distribution grid. It also has a duty to give to grid users the information they need in order to access the grid. The DSO manages and maintains the distribution grid and is in charge of the metering activities.

The distribution sector is regulated under a concession regime. A mix of "cost-reimbursement" and "incentive-based" form of regulation is applied. The regulatory framework involves a period of regulation of 4 years and an annual indexation of tariffs.

The final user can choose a distribution tariff integrated into the retail tariff (regulated or not): in this case, the supplier chosen by the customer is the one who has a contract with the DSO. Otherwise, the final user can choose a separated billing between supplier and DSO: in this case he receives two different bills and has a contract with the supplier and another one with the DSO. For electricity distribution, integrated retail tariff represents about 99% of the situations.

Key features of the regulatory regime are set out in the following table

Table 164: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession (duration between 20-30 years)
Duration of tariff setting regime	4 years
Form of determination	Regulator decides
Scope for appeal regulatory decision	Not available

Tariffs take into account costs actually paid by the operator: the concession lease and other concession costs are covered as an OPEX. Following State Council decision on electricity distribution tariff for period 2009-2013 (TURPE 3), the TURPE 4 (2014-2017) takes into account the specificities of the concession regime to define the remuneration of the operator through different rate components.

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Productivity factor is applied on some predefined OPEX. Under this scheme, DSO keeps 100% of the earnings or of the losses with respect to the predefined cost trajectory.
- Targets with premium and penalties are set on the following matters : quality of supply, quality of service

- The smart metering project is treated under a specific incentive based regulation scheme[72].

Incentive regulation interacts with the tariff level for indicators with financial incentives (bonus/malus mechanism). For instance, CRE has set a target for ERDF in 2017 of 94% of user connection to be completed within the timeframe requested by users. This rate was estimated at about 84% in 2011. Better performance than the target goal will result in a financial bonus. A lower performance than the target goal will result in a financial penalty.

At the same time the following tools are provided to mitigate risks:

- Tariff components are updated every year following a predetermined formula
- For charges which are considered to be uncontrollable by the DSO, an expense and income clawback account mechanism (CRCP) is defined[73]. For these items, it measures and offsets the differences between projected and actual expenses and income on which the tariffs are based.
- As income received for all tariff components are part of CRCP, the entire volume risk is born by consumers. Thus if demand goes down and the DSO does not obtain the revenue target in one regulatory period, in the following period tariffs will be adjusted to make-up for the missing revenues in the previous period.
- Ex-ante approval of the investments by DSO for the smart metering program[74].

Key components of quality of service regulation are:

- Monitoring of two type of indicators:

[72] An extra-remuneration is granted to the DSO in case of good performance in terms of costs, deadlines and quality of service. The maximum amount of this extra-remuneration is equal to 300 points applied to the reference costs. The operator can also get penalties in case of bad performance. The total remuneration of the project cannot be below 200 points of the specific return of the project.

[73] The CRCP is also the vehicle used for financial incentives resulting from the application of incentive regulation mechanisms. It is the account to which is posted, where relevant, DSO's surplus earnings and shortfalls. It is reconciled by adjusting the tariff scale during the annual change in tariffs. The contribution of CRCP reconciliation to the annual variation of the tariff scale is limited to +/- 2%.

The expense and income items covered by the mechanism are as follows: capital expenses; the expenses related to compensation for losses on the grids; the expenses related to access to the transmission grid; expenses related to the net book value of decommissioned fixed assets; income received for all tariff components ; income received for additional services (but those created during the regulatory period and that had not been included in tariff trajectory); income received for connection charges; R&D operating expenses (under conditions explained in section D.3.2.1 of the deliberation); financial incentives related to the various incentive-based regulation mechanisms; the results of audits conducted by CRE will be taken into account within the scope of the CRCP.

[74] For the smart metering program, the regulator appealed to an extern consultant to carry on the cost-benefit assessment of the project. This study was used to elaborate the decision leading to the launch of the project (Délibération de la CRE du 7 juillet 2011), and to evaluate the cost projection provided by the DSO and help CRE to target the regulatory scheme of the project.

- Indicators being tracked by the CRE with financial incentives allocated in function of pre-defined objectives[75].
- Indicators that are only followed up.

The areas covered by the incentive regulation of quality of service are: interventions, connections, relationship with users, relationship with suppliers, and billing.

- For quality of supply, the DSO has incentive to reduce the annual duration of power cuts (expressed in minutes) under predefined thresholds, excluding incidents caused by exceptional events (see definition below) and excluding causes relating to the public transmission network.
- The average frequency of power cuts is also followed by CRE since 2014
- DSOs shall fulfil additional requirements related to the number of interruptions and the slow voltage variations with the obligation to reinforce the network in case of complaints.
- There are contractual requirements between customers and system operators, with the obligation for system operators to compensate any damage caused to the customer whenever the requirements are not fulfilled.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

[75] The form of these financial incentives are:
- Either bonus or penalty charged on the tariff ;
- Or financial penalties paid directly by ERDF to users.

Table 165: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Some costs components are regulated under “cost reimbursement” but there are “incentive based” measures
Regulatory asset base	Assets enter the rate base at their book value which is then amortized over the regulatory asset life.
Capital expenditure	Subject to benchmarking
Approach to operating expenditure	Base on the trajectory proposed by the DSO and analysis conducted by the CRE
Form of WACC applied	Although there is no WACC formula per se, the actual financial structure of the main distribution operator is taken into account to calculate the authorized revenue.
Additional revenue items	Not applicable

3. Tariffs for distribution services

3.1. Distribution tariffs: additional issues

The Regulator is in charge of setting the distribution tariffs (based on allowed revenues).

Distribution costs (especially capital costs and costs of losses) are allocated to tariffs through hourly unit costs for using the grids and the consumption characteristics of different user categories (voltage domain, profile of consumption and duration of usage).

The total hourly unit cost attributable to a withdrawal for a given voltage domain is obtained by adding the hourly unit cost for the voltage domain in question and the hourly unit costs for the voltage domains located upstream, pro rata with the energy flows created within the latter.

Users of a given voltage domain are classed according to the duration of their usage. Each user’s duration of usage represents their rate of use of the grids and therefore forms, together with the power subscribed to, an essential variable for calculating prices for access to electrical grids.

Annual unit costs for using the grid can be expressed in terms of duration of usage. This cost function is concave given that users with a short duration of usage show a strong tendency to withdraw during peak hours. The slope and value of the origin of the tangents to the cost function correspond respectively to the energy and power coefficients for each two-part tariff with and without time differentiation. The tariff structure which follows this methodology is aimed to reduce peak consumption. Indeed users with a short duration of usage face a large energy tariff component, which is an incentive to restrict their consumption. While the economic incentive to reduce consumption is the same for any hour of the year, it is hoped that it might be effective during peak-time since a larger part of the consumption of those users occurs statistically during peak times. On the other hand, users with a long duration of usage face a large power tariff component, which is an incentive to reduce the contracted capacity, and thus their maximal consumption over the year and in particular during peak time.

The tariff charged to grid users is the sum of sub-components, all published by the regulator. The main subcomponents are:

- withdrawal components
- metering component
- administrative management component

For residential customers, the supply has to be offered and billed as integrated retail tariff. Withdrawal components of the distribution tariff could be differentiated according to time of use. Options with time differentiation are calculated such as the share of energy for each time interval is in proportion with the average unit cost for the time interval concerned[76].

Various other aspects of distribution tariff setting are summarized in the table below.

Table 166: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Cost of losses is included in the distribution tariff
Presence of uniform tariffs	The same tariff for consumers applies everywhere in the country.
Presence of non-linear tariffs	All tariff components are linear but one tariff proposed for users connected to HVA voltage domain which is concave.
Presence of regulated retail tariffs	Regulated tariffs will be abolished for consumers whose contracted power is above 36kVA in 2016. Households and small consumers (P<36kVA) will still benefit from regulated tariffs after 2016
Presence of social tariffs	There is no social network tariff implemented. Social retail tariff are implemented, under the form of a standardised bill reduction, financed by a tax paid by all consumers, called CSPE (contribution au service public de

[76] For HVA (between 50kW and 63kW), three different tariffs are proposed. Two of them have per kW and per kWh components which are time differentiated. For LV > 36kV, two different tariffs are proposed. One tariff has both per kW and per kWh time differentiated component. The other has only per kWh time differentiated components. There is no flat tariff. For LV > 36kV, three different tariffs are proposed. One of them has per kWh time differentiated component (two index, intra-day time differentiation).

	l'électricité).

3.2. Connection charges

As a general principle, grid users bear the cost of creating new electrical equipment and replacing existing equipment at the same voltage level, and the cost of creating new equipment at the voltage level immediately above. Only the works strictly necessary to the connection of a specific grid user are taken into account when calculating connection charges.

For consumers, 40% of these costs are mutualized through grid tariffs. Moreover, for residential consumers, connection charges do not include the cost of grid reinforcements in low voltage.

For RES generators, connection charges include, since the end of 2012 / beginning of 2013, on top of the aforementioned costs, a portion of the costs of the HV/MV substations and transmission lines required to reach a certain RES target on a regional basis.

Key issues in the setting of connection charges are set out in the table below.

Table 167: Summary of key issues relating to connection charges

	Issue	**Approach**
Determination of charges	Type of charges (shallow/deep)	Shallow for residential consumers and deep for generators.
	Methodology adopted	• For the smallest connection works (low voltage, power ≤ 36 kVA and distance to the distribution transformer ≤ 250 meters), connection charges are approximated, breaking down into a fixed term and, optionally, a length-dependent term. These price estimates are approved or controlled by the regulator. • For other grid users, connection charges are based on real costs. • For RES connection charges, a new scheme has been put into place since the end of 2012 / beginning of 2013: on top of their own connection charges, on a regional basis, the costs of HV/MV substations and transmission lines required to reach a certain RES target are borne by all RES generators, proportionally to their rated capacity.
Hosting capacity	Scope to refuse connection	DSOs can refuse connection of any grid user only for safety or security reasons. DSO has to refuse the commissioning of the connection of an unauthorised generator.
	Requirements to publish hosting capacity	DSOs have to publish the generation hosting capacity for each HV/MV

		substation, comprising: • Transformers capacity left • Hosting capacity of the transmission network • Total power of the power plants awaiting connection at the same substation For other voltage levels, hosting capacity is announced by the DSO when a generator asks for a binding or a non-binding connection estimate. DSOs are not required to notify to the regulator the hosting capacity of his network.
	Targets and/or incentive schemes to enhance hosting capacity	The DSO is assumed to have a duty to connect all the generation capacity or consumers which apply for connection. Moreover, hosting capacity targets for RES are set on a regional basis, at the HV/MV substations level.

4. Distribution system development and operation

Local administrations are the owners of the distribution network. Responsibility for network development is split between the DSO and local administrations.

Generally, DSOs do not have the right to dispatch. Smart grids pilot projects are in place in which battery packs or flexible loads are controlled by the DSOs.

Smart meters are already installed or are being deployed in companies. Roll-out in residential sector will start in 2015.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 168: Approach to distribution planning

Issue	Approach
Form of distribution planning document	N.A.
- Key responsibilities for its development	Local authorities are the owners of the distribution grid. By the law they are responsible for the development of the grid. However a concession regime is in place: local authorities delegate, within the framework of the concession contract, part of their responsibilities to the DSO (which is finally in charge to connect users to the grid). For electricity, about 80% of the investments on distribution grids

	are done by DSO and about 20% are done by local authorities. Local administrations organize local conferences to define the distribution grid development plan. The distribution Network development plans are not notified to the regulator nor published.
- Degree of integration with renewables plan	Renewable generation targets are set by the Government at national level and declined at regional level through "Schéma régional du climat, de l'air et de l'énergie" (named "SRCAE", regional plan of climat, air and energy), who decline their objectives renewable energy production by "Schéma regional de raccordement des énergies renouvelables" (named "S3REnR, regional plan of connecting to the network of the renewable energies). The renewable targets are thus defined by the Government and not by the regulator. The S3REnR are developed by the TSO (RTE) in agreement with the DSOs and approved by the regional prefects
- Relationship with consumption trends	The DSO has the duty to define and do the necessary investments in order to connect users to the grid he manages.
- Relationship with quality of service targets	ERDF provides during the tariff discussions the projected budget of investments which is split into big finalities. One of these finalities is the quality of supply and the modernization of the network. There has been progress in the amounts assigned to this finality: - 607M€ in 2009, - 942M€ planned for 2014, - 1 026M€ planned for 2017.
- How trade-offs between network development and alternative technologies are treated	Not treated
- Requirements to integrate cost benefit analysis	There is no legal requirements but DSOs, especially large ones, rely on cost-benefit analysis for large investments, such as primary substations. They also rely on technical-economic analysis to design broad investment policies, for instance to define sub-sections to be used at connection time, which aim to obtain an optimal balance between investment cost, future losses, and quality. Smaller DSOs tend to rely on these policies as well.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 169: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO	The DSO can only require embedded units to disconnect in case the distribution system cannot host their

network	injections.
Possibility to dispatch flexible loads	Flexible loads are all only self-dispatched. Since there is no balancing mechanism for local congestion management, DSOs are not able to dispatch flexible loads for any purpose.
Other sources of flexibility open to DSO	The DSO does not access (unless in pilot projects) to other sources of flexibilities (i.e. dynamic controllable electricity load). Nevertheless, several million households already have a time-of-use distribution tariff that includes ripple control to stagger the switch on and switch off time of electric water heaters. Currently, these switching times are defined by the DSOs for each network pocket in order to optimize peak-shaving at the global and local level. The impact of this load management is taken into account in the planning – investment and operations- of the distribution networks.

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 170: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs have full responsibility for metering (pose, metrological control, maintenance and renewal of metering device and to manage the date and all responsibilities related to all of these activities), but the meters are owned by local authorities (such as a large part of the distribution network).
Monopoly services in the metering	DSOs are monopolists in metering activities
Smart metering functionality	a) 10 minutes, half an hour or an hour measurement (remotely definable) b) remote reading c) remote disconnection/reconnection of customers d) remote control of the maximum power that can be withdrawn e) remote operation of appliances at the consumer's premises f) local port to send real time consumption information to a local screens or computers

As of 2013 there were approximately 185,000 smart meters installed in the country. A breakdown by customer category is illustrated below.

Table 171: State of smart meters deployment-2013

Customer category	
Residential	For retail market (LV less than 36 kVA), an experimentation project has been done. The effective roll-out will begin of 2015 and finish in 2021.
Small companies	For small companies (LV more than 36 kVA – around 350,000 meters), the roll-out already began and 27% of meters are smart (around 94,500). Others will be changed by 2020.
Medium companies	For medium companies (MV – around 125,000 meters), many ‘old’ meters were already smart (42 %, around 52,500) and some which were not had been changed for smart ones (23 %, around 28,750). Others will be changed by 2020.
Big companies	For big companies (HV and VHV - around 8,000 meters) ‘old’ meters were already smart.

Country Report – France (gas distribution)

1. Overview of the distribution sector

In France the distribution sector is rather concentrated, with GRDF representing around 96% of the distribution network. The sector is regulated. The DSO has a rather limited role in setting the allowed revenue and the distribution tariffs. The government maintains the power to revert the NRA deliberations if it considers that its general policy orientations have been disregarded.

1.1. Institutional structure and responsibilities

In *France* there are 26 distributors supplying gas to approximately 11 million of customers through a roughly 200,000 km gas distribution grid. Data on gas grid coverage are not available.

Summary data on industry structure is set out below.

Table 172: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand(DSOs <100000 customers)
Country	26	-	4	23	Yes	< 1%
***DSO's with less than 100000 customers can choose between legal unbundling or accounting/functional unbundling**						

The responsibility for setting distribution tariffs is spread between the following jurisdictions:

- The DSO
- The NRA (Commission de régulation de l'énergie-CRE)
- Government (Ministère de l'écologie, du développement durable et de l'énergie, Ministère de l'Economie, de l'Industrie et du Numérique)

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 173: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Sends accounting and financial data to NRA		Calculates for NRA approval
Government	Defines main principles, can ask the NRA for a new deliberation	Defines main principles	Defines main principles
NRA	X	X	X

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adopted to setting distribution tariffs involves the following steps:

- The Government elaborates general policy orientations
- The methodologies used to establish tariffs for the use of public gas transmission and distribution grids are set by the CRE;
- The DSO sends to the CRE the financial and accounting document in order to allow the regulator to fix/modify the distribution tariff levels
- The CRE takes into account the energy policy guidelines indicated by the Government and it regularly informs the Government during the tariff establishment phase.
- The CRE consults energy market stakeholders as it sees fit[77].
- The CRE transmits to Government, for publication in the *Journal Officiel de la République Française* its reasoned decisions on changes in the level and structure of distribution tariffs.
- In the following two months, the Government can ask the CRE for a new deliberation if it believes the CRE has not taken in due account the governmental general principles adopted in the domain of energy policy.

1.2. Key figures on revenue and tariffs

Distribution revenues in 2013 were € 3,3 billion. No further split by service type is available.

Distribution tariffs are not defined on "category of consumers" but on tariff options. Thus for a given consumption level, the supplier is free to choose the distribution tariff he wants.

Information on available tariff components and the number of customers in each category is set out in the table below.

[77] In the last case (almost one year process), the regulator issued one public consultation on the tariff structure and the main principles and one public consultation on the allowed revenue. It also held public hearings.

Table 174: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers[78]	Revenue
Forfait	€/year	3000	NA
T1	€/year, €/MWh	3079841	NA
T2	€/year, €/MWh	7839177	NA
T3	€/year, €/MWh	105507	NA
T4	€/year, €/MWh, €/MWh/day	2862	NA
TP	€/year, €/MWh/day, €/m[79]	58	
Total	-	11030445	NA

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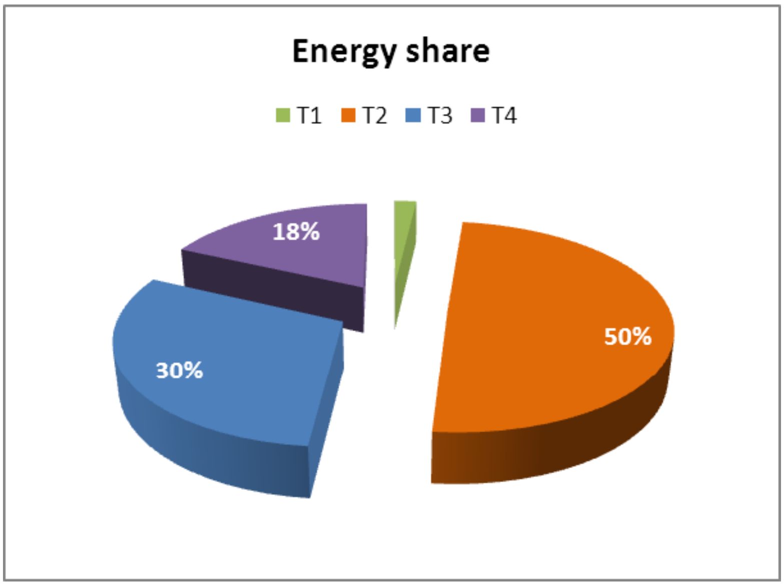
The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 41: Proportion of energy by tariff options[80]



The tariff structure comprises four main tariff options corresponding to the following customer segments:

- two-part option T1: annual consumption from 0 to 6000 kWh;
- two-part option T2: annual consumption from 6000 to 300000 kWh;
- two-part option T3: annual consumption from 300000 to 5000000 kWh;
- three-part option T4: annual consumption over 5000000 kWh.

[78] Forecasts, ATRD4 for GRDF. (year 2013)
[79] Annual distance charge.
[80] Forecasts, ATRD4 for GRDF. (year 2013)

For end customers with no individual meter or communal meter associated with a communal supply contract the tariff applicable is an annual fixed charge (forfait).

The above thresholds have been established taking account of the tariff-based supply levy ("contribution tarifaire d'acheminement" – CTA) which applies to the tariff set of charges and for a modulation of 160 days for option T4.

There is also a special tariff option, known as the "proximity tariff" (three-part TP option), reserved for end customers having a statutory entitlement to connect to the natural gas transmission network.

The shipper chooses the tariff option for a given delivery point. The tariff is applied per delivery point. A penalties mechanism applies for exceeding contracted capacities for tariff options T4 and TP.

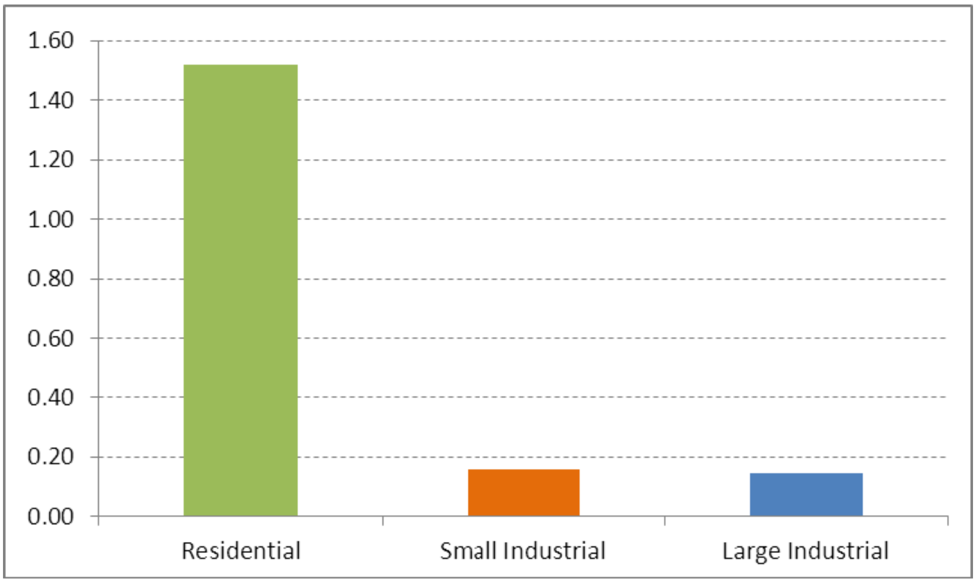
The typical network tariff in force from the 1st of July 2012 to the 30th of June 2013 for residential, small and large industrial customers is illustrated below.

Table 175: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Annual subscription charge for daily capacity	Total
Residential	15000 kWh	119,64	108,45		228,09
Small industrial	50000 MWh	13737,72	35500	30630,86	79868,58
Industrial	90000 MWh	13737,72	63900	55135,54	132773,26

The average tariffs per kWh are illustrated below.

Figure 42: Average network charges (€cent/kWh), 2013



An example of network tariffs applied in 2013, by GRDF DSO is available at the following link: http://www.cre.fr/en/documents/deliberations/decision/grdf-public-natural-gas-distribution-networks.

2. Regulation of distribution activities

2.1. General overview

The role of the DSO in France is to define and to do the necessary investments in order to connect users to the grid it manages, respecting the environment and ensuring energy efficiency. It has a duty to report every year to the local administrations (which own the gas distribution network) the state of the infrastructure developments. The DSO stipulates and manages the concession with the local administration and ensures transparent, objective and non-discriminatory access conditions to the gas distribution grid. It also has a duty to give to grid users the information they need in order to access the grid. The DSO manages and maintains the gas distribution grid and is in charge of the metering activities.

The CRE regulates the electricity and gas networks guaranteeing the right of access to public electricity grids and natural gas networks and facilities, ensuring the proper functioning and development of electricity and natural gas networks and infrastructure, ensuring the independence of system operators and contributing to building the European Internal Market for electricity and gas. It also regulates the electricity and gas markets monitoring transactions on the electricity, natural gas and CO2 markets, ensuring the proper functioning of retail markets, contributing to the implementation of measures to support electricity generation and supply of electricity and gas and informing all consumers).

The distribution sector is regulated under a concession regime. A mix of “cost-reimbursement” and “incentive-based” form of regulation is applied. The regulatory framework involves a period of regulation of around 4 years and an annual indexation of tariffs. Main incentive mechanisms are related to OPEX that can be controlled, quality of services and smart metering.

The distribution tariff is bundled into an integrated retail tariff.

Key features of the regulatory regime are set out in the following table

Table 176: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession (20-30 years)
Duration of tariff setting regime	Distribution tariffs are revised every 4 years. Current tariffs are updated every year following a predefined formula which takes

	into account predefined elements such as inflation and other elements not controlled by the DSO, such as the volume of flowed gas.
Form of determination (distributor propose/regulator decide)	Regulator decides
Scope for appeal regulatory decision	Not available

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Productivity factor on the OPEX Capital expenditure efficiencies (since prices are automatically updated each year according to a predefined rule, the DSO is incentivised to reduce costs via a productivity factor on the OPEX)
- Output based incentive regulation in the domain of quality of service and smart metering[81].

At the same time the following tools are provided to mitigate risks:

- At the end of the regulatory period (4 years), the DSO keeps 100% of OPEX savings (or losses).
- The volume (i.e. kWh only, not the number of customers connected) risk is born by consumers (if demand goes down and the DSO does not obtain the volume target for year 1, the tariff in year 2 will be adjusted to make-up for the missing revenues in year 1.
- The OPEX trajectory of DSOs may be modified after 2 years (within a 4 year tariff period) if, as a consequence of new legislation, the projected net OPEX for the remaining two years are modified by at least 1%.
- Investments for the Smart Metering Programme are approved *ex-ante*
- For some categories of expenses and income that are hard to predict or control, CRE has defined an expense and income clawback account (CRCP) mechanism[82]. It measures and

[81] The smart metering project is treated under a specific incentive based regulation scheme. An extra-remuneration is granted to the DSO in case of good performance in terms of costs, deadlines and quality of service. The maximum amount of this extra-remuneration is equal to 200 points of the specific return of the project. Besides the penalties cannot decrease the remuneration below 100 points of the specific return of the project.

[82] The CRCP is also the vehicle used for financial incentives resulting from the application of incentive regulation mechanisms. The CRCP is the account to which is posted, where relevant, DSO's surplus earnings and shortfalls. It is reconciled by adjusting the tariff scale during the annual change in tariffs. The contribution of CRCP reconciliation to the annual variation of the tariff scale is limited to +/- 2%.
The expense and income items covered by the mechanism are as follows: capital expenses, the expenses related to compensation for losses on the grids, income received for all tariff components depending on consumption, income received for additional services , financial incentives related to the various incentive-based regulation mechanisms, income received for capacities overtaking penalties, the results of audits conducted by CRE will be taken into account within the scope of the CRCP.

offsets, for previously identified items, the differences between projected and actual expenses and income on which the present tariffs are based.

Key components of quality of service regulation:

- Bonuses/penalties are applied depending on predefined targets.
- Level of bonuses, penalties and targets may be revised during the tariff period (4 years) to maintain/improve quality of service.
- Monitoring of two types of indicators by the CRE:
    - Indicators being tracked by the French NRA with financial incentives allocated in function of pre-defined objectives. The form of these financial incentives are either bonus or penalty charged on the tariff or financial penalties paid directly by the DSO to suppliers.
    - Indicators that are only followed up.

The areas covered by the incentive regulation of quality of service are: interventions, connections, relationship with users, relationship with suppliers, and billing.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 177: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Some costs components are regulated under “cost reimbursement” but there are “incentive based” measures
Regulatory asset base	Assets enter the rate base at their gross value which is then amortized over the regulatory asset life and updated by a Consumer Price Index
Capital expenditure	Historic assets and investment forecasts submitted by the operator
Approach to operating expenditure	Benchmark with the efficient operator
Form of capital remuneration applied” (WACC real, nominal, ten years Treasury bond + adder, …)	Real before tax WACC, that is updated at the beginning of each new regulatory period (i.e. every four years)
Additional revenue items (where applicable)	

The following formula is applied in determining the WACC:

$$WACC = \frac{K_e}{1-t} \times \frac{E}{E+D} + K_d \times \frac{D}{E+D}$$

Where:

- ✓ Ke = rf + β MRP is the cost of equity
- ✓ MRP is the Market Risk Premium
- ✓ Kd is the cost of debt
- ✓ t is the corporate tax rate

The gearing level taken into account in the WACC formula corresponds to a normative financial structure that is in line with European practices and sector average.

The cost of capital is estimated using the methodology known as the capital asset pricing model (CAPM).

Allowed revenue assessments are based, on assumptions of the following outputs:

- Quality of service
- Productivity factor
- Cost of gas losses and metering difference
- Investment regulation
- Promoting gas use

The regulator introduced in 2012 an incentive regulation on unit investment costs: the regulator assesses the realization of the projected investment volumes and gives a bonus to the operator if unit costs are lower than projected.

For the smart metering program, the regulator appointed an external consultant to carry on the cost-benefit assessment of the project. The incentive regulation put in place by CRE targets the consultant's cost projections.

3. Tariffs for distribution services

Distribution tariffs includes a commodity fee (predominant for small consumers), a capacity fee (predominant for big consumers), a fee proportional to the distance to the transmission network (only applied to the very large consumers).

For consumers the DSO cannot refuse requests of connections, except for safety and security reasons . For generators the DSO cannot refuse connection but it can enforce a waiting list

3.1. Distribution tariffs: additional issues

In France, the DSOs only operates low pressure network (TSOs are responsible for regional transmission networks).

The CRE is in charge of setting the distribution tariffs, which includes three different components :

- A commodity fee (predominant for small consumers)
- A capacity fee (predominant for large consumers)
- A fee proportional to the distance to the transmission network (only applied to the very big consumers)

Distribution tariffs cover the costs of an efficient operator. Thus, it could be theoretically possible to exclude investments if proven useless. In practice, CRE does not conduct ex-post assessments of the usefulness of distribution investments.

Tariffs take into account costs actually paid by the operator: investments paid for by the concession owner are not included in the RAB, however, some concession leases and other concession costs are covered as an OPEX.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 178: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Cost of losses is included in the distribution tariff.
Presence of uniform tariffs	There are 26 DSOs charging different tariffs (corresponding to its allowed revenues) set by the regulator. However, GRDF represents 96% of demand.
Presence of non-linear tariffs	All tariff components are linear
Presence of regulated retail tariffs	Regulated tariffs will disappear for non-household consumers consuming more than 30 MWh/year before January the 1st, 2016. Will remain for smaller consumers.
Presence of social tariffs	There is no social network tariff implemented. Social retail tariffs are implemented, under the form of a "Tarif spécial de solidarité".

3.2. Connection and capacity issues

Connection fees for small consumers (metered every 6 months) include either:

- Uniform fixed fee;
- Uniform fixed fee plus the cost of network expansion;
- Exclusively cost based when connections are particularly long or expensive.

Key issues in the setting of connection charges are set out in the table below.

Table 179: Summary of key issues relating to connection charges

	Issue	Approach
Determination of	Type of charges	Shallow. Costs of reinforcement are not

charges	(shallow/deep)	covered
	Methodology adopted	Standard costs are approved by the regulator for both uniform and client-specific connection fees. For larger consumers or generators the DSO makes an estimate based on its cost but the client is free to procure the necessary works from a different source.
Hosting capacity	Scope to refuse connection	For consumers the DSO cannot refuse requests of connections, except for safety and security reasons[83]. For generators the DSO cannot refuse connection but it can enforce a waiting list. In case of refusal of connection, the regulator is notified and can be asked by the party seeking connection to revert the DSO's decision
	Requirements to publish hosting capacity	None, but the CRE can ask for it during a settlement of dispute

4. Distribution system development and operation

Local administrations are the owners of the distribution network. Responsibility for network development is split between the DSO and local administrations.

Only the smart meter roll-out (starting in 2016 for retail market and small companies) is subject of an *ex-ante* form of approval by the regulator.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 180: Approach to distribution planning

Issue	Approach
Form of distribution planning document	
- Key responsibilities for its development	Quite all of the investments on distribution grids are done by DSO except small development supported by land developers for example
- Degree of integration with environmental policies	None
- Relationship with quality of service targets	None
- How trade-offs between network development and alternative technologies are treated	The network development plan reports only the decisions of the DSOs. The analysis on which those decisions are based are not public.

[83] In case of no rentability of the connection, the DSO can ask for a financial contribution to the consumers.

- Requirements to integrate cost benefit analysis	Only smart meters roll out is conditioned by a CBA conducted by the regulator, which is published.

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 181: Key approach to metering

Issue	Approach adopted
DSOs role in metering	The DSO: a) owns the meter b) is responsible for the collection of data from the meter c) is responsible for all other data management functions (validation, storing, sending the data to parties entitled access to them ...)
Monopoly services in the metering	DSOs are responsible for metering. However, DSOs can externalize the collection of the metering data.
Smart metering functionality	• Remote reading • Automatic collection and transmission of the metering data to the gas suppliers (on a monthly basis) • Local port and web site to give real time access to estimated consumption information

As of 2013 there were no smart meters installed in France. In early 2016 a project pilot concerning the installation of 150000 smart meters for the retail market and small companies will start. This project will end in 2022 (installation of 11 million of smart meters).

Country Report - Greece (electricity distribution)

1. Overview of to the distribution sector

The distribution sector is dominated by the one DSO operating in Greece; that DSO is part of a vertically-integrated company which also undertakes activities in the generation and supply segments.

The NRA is responsible for setting the distribution tariffs for electricity customers, and the DSO publishes and applies them.

1.1. Institutional structure and responsibilities

In Greece there is 1 distributor supplying electricity to 7179314 customers. Summary data on the industry structure is set out below.

Table 182: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	1		Ex-Vertically-integrated monopoly	0	Yes, embedded generators do not pay distribution tariffs	0%
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

The responsibility for setting distribution tariffs is spread between the following jurisdictions (for example):

- The DSO submits proposals for the allowed revenues
- The NRA issues a distribution tariff calculation methodology; it also approves the final allowed revenues and tariffs.
- Government issues the guiding principles in the primary law.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 183: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Submits proposals to NRA	Not involved	
Government	Defines main principles	Not involved	Issues the principles in the primary law
NRA	Issues the calculation methodology and approves final values	Sets the structure (following consultation)	Sets and issues the methodology

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process to setting distribution tariffs involves a consultation process, wherein only the methodology undergoes public consultation. Tariffs are set by the Regulator following a proposal by the DSO.

1.2. Key figures on revenue and tariffs

Distribution revenues in Greece in 2013 were €776,8 million. There is no separation of the total allowed revenues for different activities.

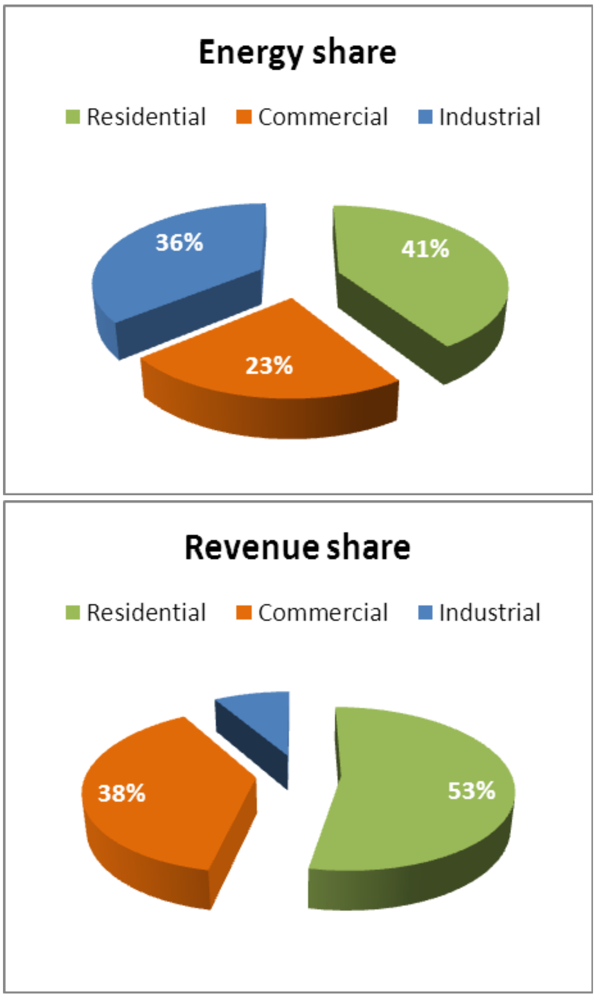
A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 184: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers
MV	KWh; max. demand	10241
LV (w. Reactive power metering)	KWh, KVA	36244
LV (w/o reactive power metering)	KWh, KVA	113107
Domestic w. Social tariff	KWh, KVA	5704485
Other LV (subscribed demand <25 kVA	KWh, KVA	1315237
Total	-	7179314

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 43: Proportion of energy and revenue accounted by customer categories



These show a disproportionate share of costs borne by residential and commercial consumers. Industrial consumers consume a significantly larger proportion of the overall energy consumed, in comparison to their collective contribution to the total revenues.

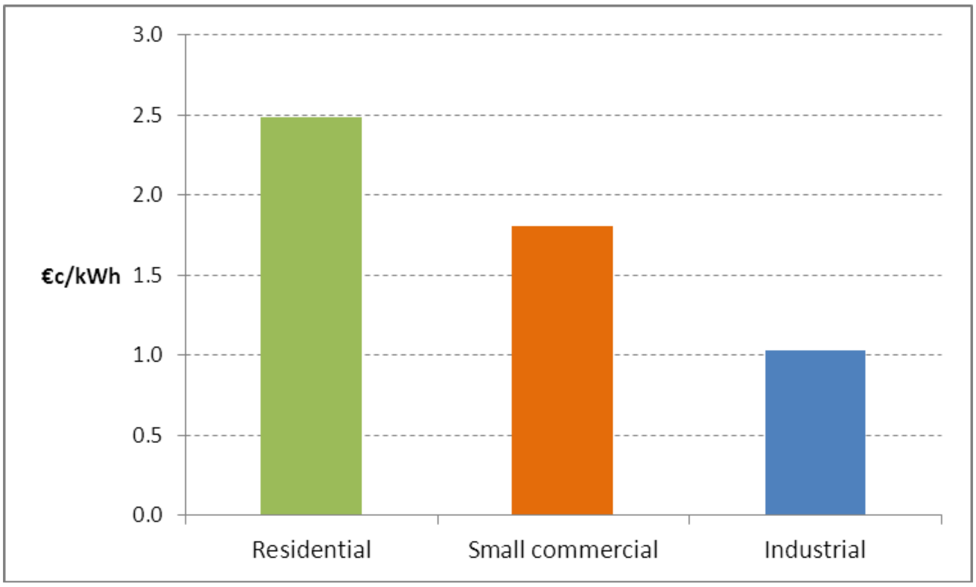
The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below:

Table 185: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Demand and reactive charges	Total
Residential	3500kWh	16	71	-	87
Small commercial	50MWh	108	795	-	903
Industrial	24000MWh	177840	69600	-	247440

The resulting average tariffs per kWh are illustrated below.

Figure 44: Average network charges (€cents/kWh), 2013



2. Regulation of distribution activities

> A cost-plus regulatory regime is used, and allowed revenues are decided on an annual basis by the regulator.
>
> There are no specific performance incentives in use.

2.1. General overview

The distribution sector is regulated under a cost-plus regulatory regime, wherein allowed revenues are decided each year by the regulator. The regulator is currently considering adjusting the regime to include a multi-year incentive based regulatory regime. The current model does not provide for any explicit performance incentives.

No formal methodology exists to analyse the DSO´s investment requirements and no ex post assessment of investment usefulness is undertaken.

Key features of the regulatory regime are set out in the following table

Table 186: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	License. There is one nationwide distribution network, owned by the ex-vertically integrated utility (PPC). The system operator of the nationwide distribution network (the PPC distribution division spin-off) has been appointed by law and licensed by the Regulator for an indefinite period of time.
Duration of tariff setting regime	Allowed tariffs are only set for one year ahead.

	The regulator is considering the possibility of switching to a multi-year tariff model.
Form of determination (distributor propose/regulator decide)	The DSO proposes and the NRA decides on the final structure / calculation methodology

2.2. Main incentive properties of the distribution regulatory model

There are no explicit regulatory incentives provided for DSOs in the Greek electricity distribution regulation. However, the DSO is incentivised to realise efficiency improvements because their OPEX allowance is set that any realised OPEX within a +/- 3% range of the agreed OPEX is allowed to be kept by the DSO. Outside of this range, there may be ex post adjustments.

There is no quality of service regulation.

At the same time the following tool is provided to mitigate risks. The revenue target is set in terms of total revenues and the entire volume risk is born by consumers (hence, if demand goes down and the DSO does not achieve its revenue target in a year, in the following period the tariffs will be adjusted to make-up for the missing revenues). Therefore, allowed revenues are always effectively recovered.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 187: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Cost-plus
Regulatory asset base	Based on the book values in 2009 without taking into account the latest revaluations for IFRS purposes. RAB is adjusted each year for new investments and assets taken off-line.
Capital expenditure	Not specifically analysed. A 'soft' approval approach is followed, whereby DSO annual investment proposals are loosely examined considering historic trends and future projections, with emphasis on significant deviations
Approach to operating expenditure	Price cap, with allowed +/- 3% range (deviations outside this range are recovered in the following year tariffs).
Form of WACC applied	Not applied

3. Tariffs for distribution services

Tariffs are set annually by the regulator; they are established using an informal methodology, and costs which were not recovered in prior years are recovered within the subsequent year´s tariffs.

Connection charges are generally deep in nature. The DSO is generally required to provide a connection to all new renewable generation capacity.

3.1. Distribution tariffs

There is currently no formal methodology set for the calculation of the allowed distribution revenue, given that the Distribution Network Code (which will include the methodology for estimating the annual distribution costs) has not been adopted yet.

For the purpose of calculating Distribution Use of System (DUoS) charges, customers are categorised based upon their connection voltage and metering capabilities. Consumers are separated into five (5) categories: MV customers, LV customers with subscribed demand >25 kVA (with and without reactive power metering), LV residential customers, and other non-residential LV customers. For MV customers, 50% of the cost is recovered through a capacity charge and 50% through an energy charge. For domestic customers, 10% of the cost is recovered through a capacity charge and 90% through an energy charge. For Other LV customers the splits between capacity charges and energy charges are 20% and 80%, respectively.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 188: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Network use of system charges are applied on metered (delivered) energy. As a result, charges do not include the effect of network losses. All network losses are incorporated in the competitive tariff element (covering the cost of generation and supply activities)
Presence of uniform tariffs	Yes
Presence of non-linear tariffs	No, all tariff components are linear
Presence of regulated retail tariffs	No
Presence of social tariffs	Yes

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 189: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Deep charges for embedded generators and isolated/remotely located consumers. Partially deep charges for all other consumers
	Methodology adopted	Standard costs and cost coefficients approved by the regulator for both for uniform and client-specific connection fees. Generators are free to procure the necessary works from a different source.
Hosting capacity	Scope to refuse connection	For consumers and generators the DSO can temporarily refuse connection only in case where it lacks the necessary network capacity.
	Requirements to publish hosting capacity	There is no explicit requirement on the DSO to publish hosting capacity information. However there have been specific circumstances where the Regulator requested such a publication to be made for transparency reasons.
	Targets and/or incentive schemes to enhance hosting capacity	No, the DSO is assumed to have a duty to connect all the renewable capacity that applies for connection, notwithstanding the case it lacks necessary network capacity

The DSO is required to notify the regulator of the hosting capacity of their network, upon request and also when the hosting capacity is exhausted or nearing exhaustion on the basis of existing connection requests in any particular area.

4. Distribution system development and operation

A distribution network development plan is supposed to be published, but in practice this does not happen; instead the DSO submits its annual investment plan, which is informed by, and informs, the annual revenue setting process.

Renewable generators are ´must run´ on the basis that they do not compromise system security.

Around 11.000 medium voltage customers currently have a smart meter installed and there are plans for further rollout of meters to other customers in Greece.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 190: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Multi-year distribution network development plan
- Key responsibilities for its development	Legislation provides for regulatory approval of a multi-year distribution network development plan. However these provisions are yet to be put into practice and no such development plan has been submitted by the DSO for regulatory approval. The DSO currently submits an annual investment program, as part of the annual revenue setting process.
- Degree of integration with renewables plan	The DSO, in developing its plan, generally takes into account the foreseeable demand for connection of renewable generation connections in drafting its annual network investment program.
- Relationship with consumption trends	No specific relationship, but forward consumption is generally considered.
- Relationship with quality of service targets	No quality of service targets are set by the regulator
- How trade-offs between network development and alternative technologies are treated	No specific treatment. The annual network investment program refers only to the result of the decisions of the DSO. The analyses on which those decisions are based are not public.
- Requirements to integrate cost benefit analysis	No requirement to integrate the CBA results. The annual network investment program refers only to the result of the decisions of the DSO. The analyses on which those decisions are based are not public.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 191: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	All renewable generation is injected in the distribution network without being subject to dispatch instructions (priority dispatch), and on the condition that system security is not compromised.
Possibility to dispatch flexible loads	The system operator controls all flexible loads.
Other sources of flexibility open to DSO	There are no market-based balancing or voltage regulation mechanisms / resources.

4.3. Metering

Key issues regarding metering, and the role of the DSO is set out in the following table.

Table 192: Key approach to metering

Issue	Approach adopted
Discos role in metering	The DSO has full responsibility for metering and also own the meters.
Monopoly services in the metering	The DSO is a monopolist in metering services
Smart metering functionality	Quarter of an hour measurements Remote reading Remote disconnection and reconnection of customers Remote control of the maximum power that can be withdrawn Local port to send real time consumption information to local screens/computers.

As of 2013 there were around 11.000 smart meters installed in Greece. Specifically, all medium voltage customers are equipped with smart meters. A breakdown by customer category is illustrated below.

Table 193: Number of smart meters installed – by end of 2013

Customer category	Number
Residential	0
Commercial (Medium Voltage customers)	Approximately 11000
Industrial	0
Total	Approximately 11000

The following information describes the plans for rolling out smart meters in Greece:

- All large (≥85kVA) low voltage consumers (approx. 60000) in 2016;
- Large pilot on smart meter deployment for LV customers (160000 metering points, all LV customer categories) in 2017; and
- Eventually, there will be a full-scale smart meter rollout.

At the current time, there has been no formal evaluation of the impact of smart meter rollout, for example no information exists concerning the reduction in energy consumption of an average medium voltage electricity customer.

Country Report – Greece (gas distribution)

1. Overview of to the distribution sector

The regulatory regime covering the distribution sector is currently being reformed. At present, distribution activities are not unbundled from other gas supply activities.

1.1. Institutional structure and responsibilities

In Greece there are 3 distributors supplying electricity to 307060 customers. Summary data on industry structure is set out below.

Table 194: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	3	0	0	2	Unconfirmed	Unknown %
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

At the current time, distribution tariffs are included in the final supply tariff to customers. Distribution tariffs are not calculated separately from supply tariffs. Similarly, the allowed revenues of each Greek DSO are not separated into distribution-related costs and supply-related costs. Rather, each DSO has allowed revenues which are a single value and is supposed to cover all aspects of gas supply (i.e. distribution and supply).

DSOs´ activities have not yet been unbundled from supply activities. However, this situation is under review and a major reform of the regulatory regime for gas distribution is currently underway; the outcome will be that the gas distribution sector is unbundled from other supply activities.

The allowed revenues of DSOs for distribution activities are set on a DSO-specific basis by the NRA, and are established within the company´s concession agreement. The overall allowed revenues of each DSO cover all activities, including supply and distribution.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 195: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Not involved	N.a. (Distribution tariffs are not established; rather, distribution costs are included in overall supply tariffs).	Calculates on case-by-case basis for customers with demand < 100 m3/h.
Government	Not involved	N.a. (Distribution tariffs are not established; rather, distribution costs are included in overall supply tariffs).	Not involved
NRA	Sets allowed revenues (within each DSO´s concession agreement)	N.a. (Distribution tariffs are not established; rather, distribution costs are included in overall supply tariffs).	Sets a standard connection fee which applies for all residential, commercial and small industrial customers.

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

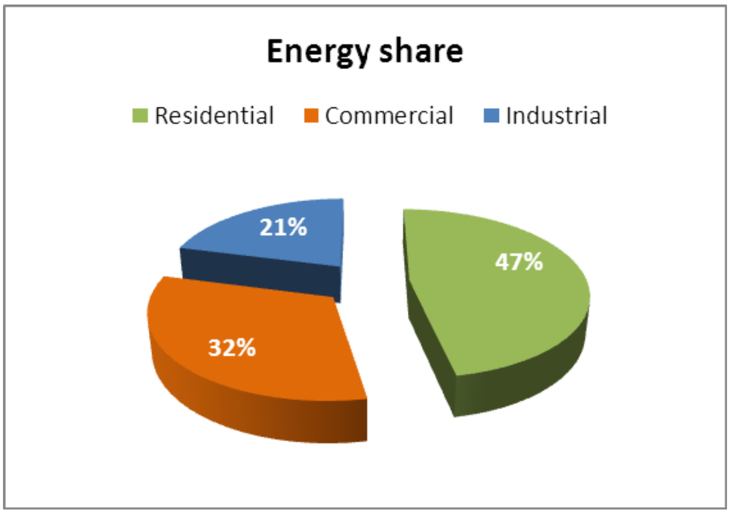
1.2. Key figures on revenue and tariffs

According to the Greek regulator, it is not possible to ascertain the amount of allowed revenues for DSOs operating in the Greek gas sector, because distribution allowed revenues are bundled together with the allowed revenues of other activities, particularly gas supply. A similar situation exists concerning understanding the different tariff components used by a DSO to recover costs for distribution activities. Specifically, DSOs are not required to, and do not, publish the specific tariff components they use to recover costs related to their distribution activities. Distribution tariffs are bundled together with retail tariffs: retail and distribution tariffs are calculated using the same methodologies.

The gas distribution sector is currently undergoing a significant regulatory reform process, and the outcome will be that the distribution segment is unbundled from other segments. This implies that in the future allowed revenues will be calculated for gas DSOs´ distribution activities, and a responsible entity (most likely the DSOs themselves, or the NRA) will be required to develop tariffs for customers specifically for distribution services.

As a result of the above-described current tariff arrangement, it is not possible to calculate the respective revenues which DSOs received from each customer class in 2013 (this information is not available). For the same reason, it is not possible to calculate an average per-kWh distribution network tariff for residential, small commercial and industrial customers in Greece. However, it is possible to provide a breakdown of the energy volumes by customer category in 2013, as shown in the chart below.

Figure 45: Proportion of energy accounted by customer categories



2. Regulation of distribution activities

Distribution tariffs are bundled within an integrated retail supply tariff. A revenue cap, set by the NRA for each DSO, is used to limit the revenues of each DSO.

Concessions of 30 years are currently used; this arrangement is likely to change following the reform of the distribution sector regulatory regime (currently underway).

2.1. General overview

The distribution sector is regulated under a revenue cap regulatory regime. The NRA sets the allowed revenues of each DSO. DSOs are then allowed to maximise their revenue by using any pricing methodology they choose, but their revenues must not be above the maximum revenue level as set in their licenses and which takes into account revenues, Opex and Capex.

The distribution tariff is bundled into an integrated retail supply tariff.

Key features of the regulatory regime are set out in the following table

Table 196: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concessions, typically of 30 years. However, according to the NRA, existing concessions are will be broken because the distribution regulatory regime is currently being adjusted.
Duration of tariff setting regime	N.a.
Form of determination (distributor propose/regulator decide)	The NRA sets the allowed revenue, through a revenue cap
Scope for appeal regulatory decision	No scope of appeal.

2.2. Main incentive properties of the distribution regulatory model

DSOs are incentivised in their regulated activities not through specific incentive mechanisms, but rather through the potential to maximise their revenues using any pricing methodology they choose. This is bound by the revenue cap set by the NRA. For example, assuming they stay within the revenue cap, DSOs can, for example, be incentivised to improve performance efficiency through being able to keep any cost savings as a result of operating more efficiently.

There are no types of risk mitigation measures in use. Similarly, there is no specific quality of service regulation in use in the distribution sector.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 197: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue cap
Regulatory asset base	There is currently no RAB
Capital expenditure	Not specifically assessed, to be covered within the allowed revenue value of each DSO
Approach to operating expenditure	Not specifically assessed, to be covered within the allowed revenue value of each DSO
Form of WACC applied	N.a.
Additional revenue items (where applicable)	N.a.

3. Tariffs for distribution services

It is not possible to isolate and examine the tariffs for distribution services, and there is no specific methodology in use to allocate the costs of distribution activities to tariff components.

3.1. Distribution tariffs

As described above, there is no specific methodology in place to allocate distribution costs to tariff components.

Various aspects of the current arrangements for distribution tariff setting are summarized in the table below.

Table 198: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	N.a.
Presence of uniform tariffs	No
Presence of non-linear tariffs	N.a.
Presence of regulated retail tariffs	NRA sets a revenue cap for retail tariffs
Presence of social tariffs	No

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 199: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Shallow
	Methodology adopted	For residential, commercial and small industrial (<100m3/h) there is a one-off connection fee. For larger consumers connection fees are computed case by case.
Hosting capacity	Scope to refuse connection	DSOs cannot refuse requests for connection that lie up to 25 meters away of its system. In the event that a connection is refused the NRA is notified
	Requirements to publish hosting capacity	N.a.
	Targets and/or incentive schemes to enhance hosting capacity	N.a.

4. Distribution system development and operation

DSOs develop and provide distribution planning documentation to the NRA; however, the NRA is not required to provide any form of approval on the documents. Moreover, the guidelines for developing the planning documents are not stringent, and do not require the DSOs to specifically consider, for example, consumption trends, quality of service targets, or the integration of new technologies.

DSOs are fully responsible for metering activities. There are no smart meters currently installed in the Greek gas distribution segment.

4.1. Distribution system devlopment

The key features of distribution system planning are summarized below.

Table 200: Approach to distribution planning

Issue	Approach
Form of distribution planning document	DSO system development plan
- Key responsibilities for its development	DSOs develop their plans and submit them to the NRA. The NRA is not required to approve the plan
- Degree of integration with renewables plan	No integration
- Relationship with consumption trends	Not explicitly considered
- Relationship with quality of service targets	Not explicitly considered
- How trade-offs between network development and alternative technologies are treated	Not explicitly considered
- Requirements to integrate cost benefit analysis	No requirement

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 201: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs (which are the same companies as the retail service providers) are fully-responsible for metering services provision, they also own the meters.
Monopoly services in the metering	Yes, they are monopoly service providers
Smart metering functionality	Such meters are not currently deployed or in use.

As of 2013 smart meters were basically not installed in the gas distribution sector of Greece. The decision not to proceed with installing smart meter technologies was based on the findings of a cost benefit analysis undertaken. According to the NRA the analysis found that, overall, the installation of smart meters would result in an increase in tariffs.

Country Report – Croatia (electricity distribution)

1. Overview of the distribution sector

There is a single DSO, which is legally unbundled but controlled by the integrated electricity company (HEP). Tariffs are still regulated on a rate of return, annual basis. Quality of service regulation is under preparation. There is no information about smart meters or their development plans.

1.1. Institutional structure and responsibilities

In *Croatia* a single company operates distribution. It is legally unbundled and owned by the integrated state-owned operator (HEP) supplying more than 2,3 million customers and covering the whole country.

Table 202: DSO characteristics

Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
1	-	1	-	Embedded generators only pay metering	N.A.
***exemption from distribution network charges for certain types of grid users, such as generation connected to distribution networks.**					

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 203: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Proposes		
Parliament	Issues principles in the primary law	Issues principles in the primary law	
NRA	Approves proposal or rejects – if rejects, sets AR	Sets tariff structure after public consultation	Issues a methodology, calculates

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

There are no public consultations.

1.2 Key figures on revenue and tariffs

Distribution allowed revenues in 2013 were 429,26 million EU, of which 382,57 for distribution and 46,7 for metering activities. No further revenue breakdown is available.

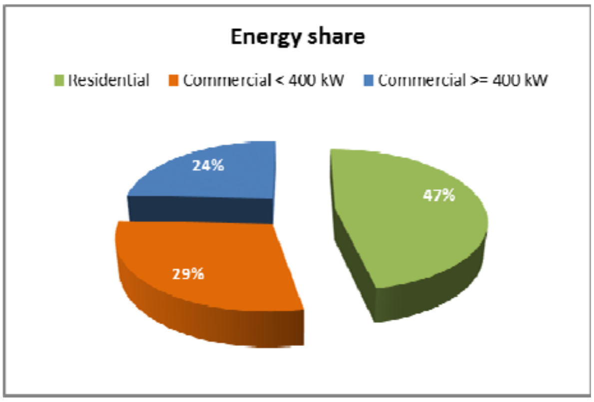
A breakdown of the number of customers, energy delivered and the revenue by customer category, including information on available tariff components, is set out in the table below.

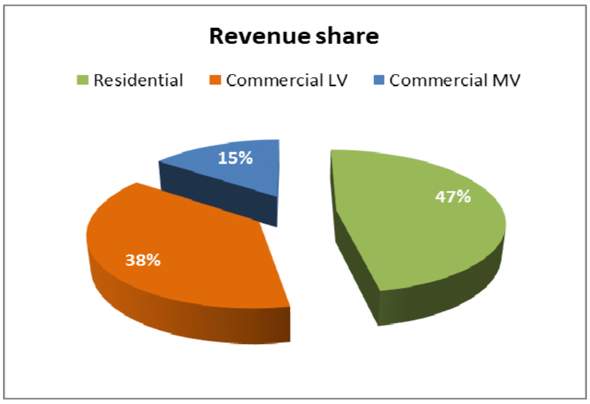
Table 204: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Delivered energy (TWh)	Revenue (million EUR)
MV	kWh & KW &fixed	2126	3,507	64,4
LV > 30 kW	kWh & KW & fixed	17828	2,629	163,1
LV <= 30 kW, non-households, dual tariff	kWh &fixed	125288	1,262	
LV <= 30 kW, non-households, single tariff	kWh & fixed	46920	0,248	
Public lighting	kWh only	21731	0,432	
Households dual tariff	kWh & fixed	1376617	4,668	201,8
Households single tariff	kWh & fixed	757757	1,561	
Households with load control	kWh & fixed	3098	0,078	
Total		**2309137**	**14,385**	**426,3**

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 46: Proportion of energy and revenue accounted by customer categories





The split seems to favour households, which pay on average less than small commercial users, due to higher costs of metering services for small commercial users (See also Figure 2 below).

The official consumer categories are related to supply voltage, peak power and usage, and are described in Table 3 above. Typical customers are:

A. Household: 3,5 MWh/y; HT/LT: 70/30

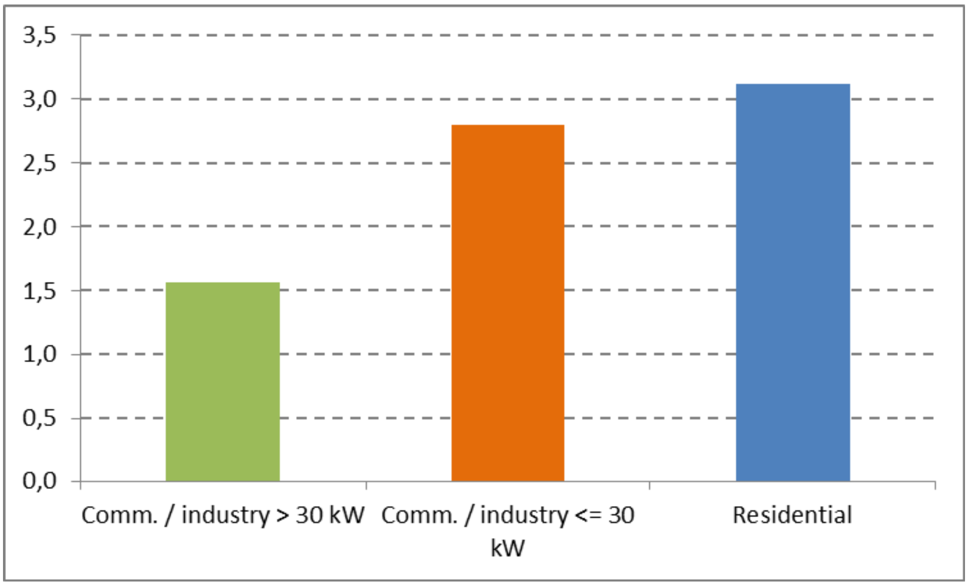
B. Middle business: 150 MWh/y; HT/LT: 70/30; Peak power: 50 kW

C. Middle industry: 2000 MWH/y.; HT/LT: 65/35; Peak power: 500 kW

D. Big industry: 24000 MWh/y; HT/LT: 60/40; Peak power 4000 kW

The average tariffs per kWh for the standard typical customers in 2012 (latest available year) are illustrated below.

Figure 47: Average network charges (€c/kWh), 2013



2. Regulation of distribution activities

2.1. General overview

Key features of the regulatory regime are set out in the following table.

Table 205: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	License
Duration of tariff setting regime	1 year
Form of determination (distributor	DSO proposes allowed revenue, NRA

propose/regulator decide)	approves and sets the tariff structure
Scope for appeal regulatory decision	N.A.

2.2. Main incentive properties of the distribution regulatory model

Croatia uses a rate of return (cost of service) regulatory approach. The Allowed Revenue comprises planned capex and opex for the next regulatory period (year). Thus, the incentive properties of the regulatory regime are very limited.

There are no specific risk mitigation provisions. However, the planned revenue for the next year is corrected by the difference between planned and realised revenue for the past year. Moreover, riskier investments receive a more favourable treatment, as explained in the below description of the WACC formula.

Quality requirements are under preparation, pursuant to the electricity law.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 206: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Rate of return (cost of service)
Regulatory asset base	Book value of assets
Capital expenditure	Assessed every year
Approach to operating expenditure	Assessed every year
Form of capital remuneration applied	Real WACC;
Additional revenue items (where applicable)	Not applicable

Weighted average costs of capital (PPTK) after taxation is calculated in the following way:

$$PPTK = re\frac{E}{E+D} + rd\frac{D}{E+D} \cdot (1 - \frac{gd}{100})$$

E – equity capital,

D – debts,

re – return on equity [%],

rd – average interest rate on liabilities [%] and pd – profit tax [%]

-return on equity re is determined as:

re = rf + (rm – rf) . β

Whereby individual items are the following:

rf – return on risk-free investments [%],

rm – average return on risky investments (expected return on market portfolio)

[%],

(rm – rf) – market risk premium [%],

β – variability coefficient of return on energy operator's shares in relation to

average variability of return on all shares quoted on the market and

(rm – rf) . β – market risk premium for own capital [%].

The debt leverage is set at the real ratio of the distributor's mother company.

3. Tariffs for distribution services

The tariff structure includes two time zones and is based on energy only for smaller customers, and on peak and energy for metered loads. There are also fixed terms, which cover metering costs.

3.1. Distribution tariffs

Customers are divided in the following categories:

1. Entrepreneurs (non-households):

(a) customers on high voltage grid who pays only transmission fee

(b) customers on medium voltage grid

(c) customers on low voltage grid:

- with power metering

- without power metering

- public lightning

2. Households

For all consumers, tariff elements cover the costs for usage of the distribution network as follows:

1. Charge for metering service (Kn/monthly),

2. Active power (Kn/kW) for MV and LV customers (> 30 kW),

3. Active energy for all customers (Kn/kWh) and

4. Excess reactive energy (Kn/kvarh) for entrepreneurs (non-households).

There are two different active energy components in peak (8 – 21 hours) and off-peak (21 – 8 hours) times. The ratio between the higher daily rate (VT) and the lower night rates (NT) for electricity taken over for customer categories with dual-tariff meters is approximately 2:1.
Various other aspects of distribution tariff setting are summarized in the table below.

Table 207: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included in distribution tariffs
Presence of uniform tariffs	Yes, for the whole country%
Presence of non-linear tariffs	No
Presence of regulated retail tariffs	For households only
Presence of social tariffs	No

Embedded generators only pay any metering charges.

3.2. Connection and capacity issues

Key issues in the setting of connection charges are set out in the table below.

Table 208: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Deep
	Methodology adopted	Standard or actual cost
Hosting capacity	Scope to refuse connection	No, if connection fee is paid
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	No. The DSO has the duty to connect all generators.

Customers' connection fee is fixed in kn/kW, based on standard costs. If planned connection costs exceed 20 % of costs based on fixed amount (kn/kW) x power (kW) than the customer has to pay all real costs.

Generators must pay all real costs.

4. Distribution system development and operation

Decisions are taken by DSOs, which have an obligation to supply all customers

4.1. Distribution system development

Investments plans (10 years, 3 years, 1 year investments plans) are subjects of official approval.

The key features of distribution system planning are summarized below.

Table 209: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Approved by regulator and published
Key responsibilities for its development	DSO
Degree of integration with renewables plan	RES targets and the distribution development plan are not explicitly related.
Relationship with consumption trends	Explicitly taken into account, with spatial detail
Relationship with quality of service targets	No explicit connection
How trade-offs between network development and alternative technologies are treated	The network development plan reports only the decisions of the DSOs. The analysis, on which those decisions are based, are not public.
Requirements to integrate cost benefit analysis	No

The analysis of the link between grid investment (including smart grid technologies), RES targets, and quality of service and demand flexibility is under preparation.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 210: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	Smaller embedded generators (like residential PV) are not dispatched. The DSO can only require larger embedded units to disconnect in case the distribution system cannot host their injections
Possibility to dispatch flexible loads	The DSO can directly control flexible loads through remotely operated switches – ripple control.
Other sources of flexibility open to DSO	No

DSOs must comply with TSO directives.

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 211: Key approach to metering

Issue	Approach adopted
Discos role in metering	Full responsibility
Monopoly services in the metering	Yes, DSO
Smart metering functionality	Yes, for customers with subscribed power > 30 kW

There is no information about deployment or plans for smart meters.

Country Report – Croatia (gas distribution)

1. Overview of the distribution sector

There are 35 DSOs, but only one has more than 100000 end customers and is legally unbundled. All other DSOs are functionally unbundled.

1.1. Institutional structure and responsibilities

Gas distribution is operated on a concession regime for the distribution system and another for construction, which are tendered for a period of a minimum of 20 and a maximum of 30 years. A concession is issued by regional self-government.

In case of renewal, the DSO that loses the concession is remunerated on the basis of its concession contract terms.

All DSO that came from horizontally integrated undertakings are at least legally unbundled from non-energy activities, and those from vertically integrated ones have at least implemented accounting and functional unbundling provisions.

The only DSOs with more than 100000 customers is Gradska plinara Zagreb d.o.o. (Zagreb Gas Works Ltd).

Table 212: DSO characteristics

Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Share of total demand (< 100,000 customers)
36	-	13	34	61.8%

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 213: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Calculates after methodology	Defines within methodology	Calculates after methodology
Ministry/Parliament	Issues principles in the primary law	Issues principles in the primary law	Issues principles in the primary law
NRA	Defines a methodology, approves/rejects.	Defines a methodology, approves/rejects.	Defines a methodology, approves/rejects.

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

In the process of adopting the methodology, the Regulatory Agency ensures appropriate participation of all stakeholders and conduct a public consultation which should last at least 15 days. In the last case, it lasted for 25 days.

1.2. Key figures on revenue and tariffs

Distribution allowed revenues approved for 2014 amounts to 72,9 million EU, of which 2,5 for connection fees and capacity enhancements, 2,4 for non-standard services and 5,9 for other services, the remaining 62,1 for distribution and metering activities.

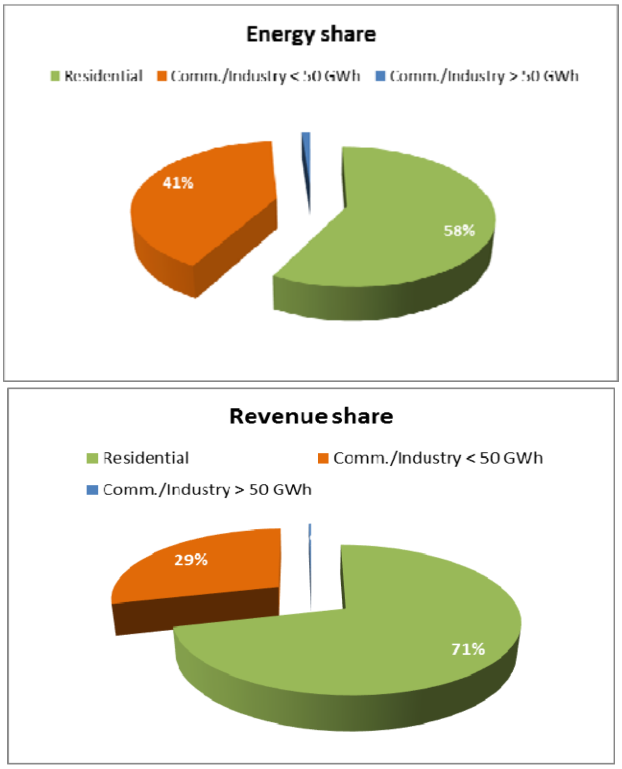
A breakdown of the number of customers, energy delivered and the revenue by customer category, including information on available tariff components, is set out in the table below.

Table 214: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Delivered energy (GWh)	Revenue (thousand EUR)
TM1 (households)	kWh &fixed	599019	6153	44049,3
TM2 ≤ 10 GWh	kWh &fixed	52013	3260	14582,0
TM3 > 10 ≤ 50 GWh	kWh &fixed	63	1109	3187,3
TM4 > 50 GWh	kWh & fixed	4	124	140,9
Total		**651099**	**10646**	61959,4

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 48: Proportion of energy and revenue accounted by customer categories



The split seems reasonably in line with costs.

There are no official typical customers in Croatian gas industry.

The average distribution tariffs per kWh for the standard typical customers in 2013 and for the official customer groups are illustrated below.

Figure 49: Average network charges for standard customers (€c/kWh), 2013

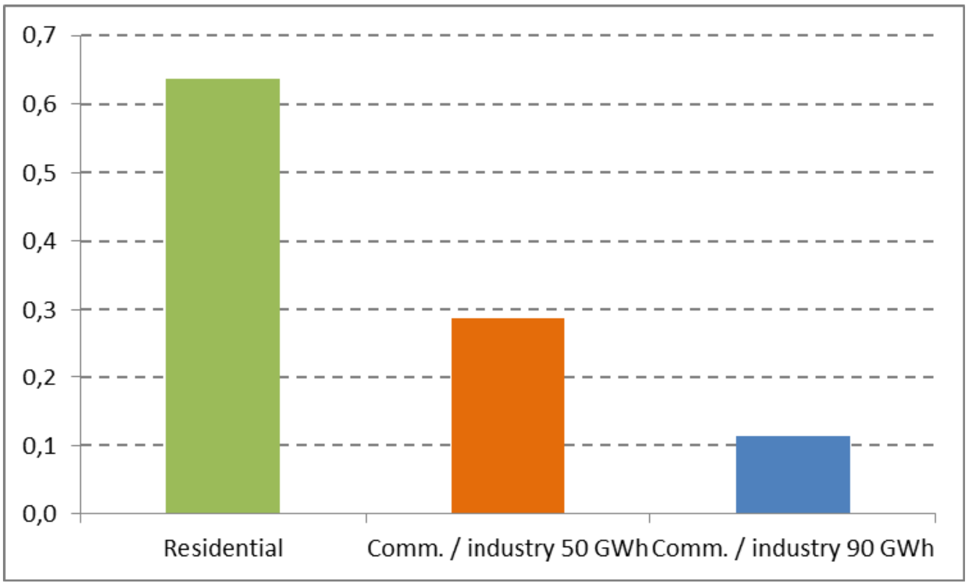
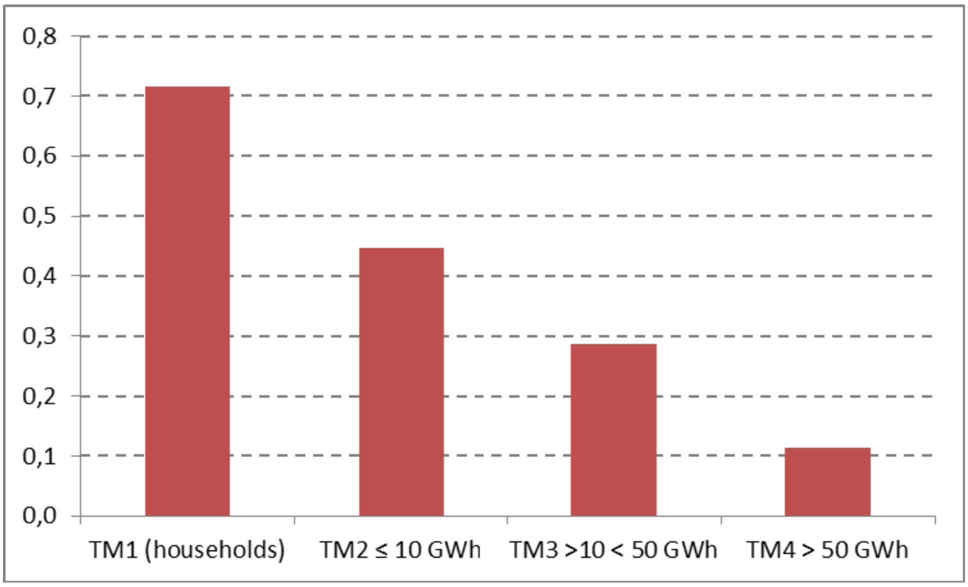


Figure 50: Average network charges for official customer groups (€c/kWh), 2013



2. Regulation of distribution activities

2.1. General overview

Key features of the regulatory regime are set out in the following table.

Table 215: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession
Duration of tariff setting regime	3 years since 2014 (5 years since 2017)
Form of determination (distributor propose/regulator decide)	DSO proposes allowed revenue and tariff structure, NRA approves or (if proposal rejected) sets the tariff structure
Scope for appeal regulatory decision	N.A.

2.2. Main incentive properties of the distribution regulatory model

The gas distribution tariff system has been reformed recently. An Incentive-based method of maximum allowed revenue (revenue cap) has been introduced. The allowed revenue is set for regulatory period, based on planned CAPEX, with an ex-post adjustment based on real values (but only up to the economically efficient level). OPEX is projected for the regulatory period based on 1+CPI-X formula, without ex-post adjustment, and if realized below projected level profit-sharing mechanism applies. For the first period (2014-16) the X-factor is set to zero.
The 1st reg. period lasts 3 years (2014-2016) and the subsequent regulatory periods will last 5 years.

By the "profit sharing mechanism", at the beginning of a new regulatory period the new starting OPEX (as part of allowed revenue) is set in a way that 50% of the efficiency gains (in excess of the OPEX cap) obtained by the firm in the previous period are not transferred to consumers in the form of reduced tariff.

The revenue target is set in terms of total allowed revenues (calculated per year and then smoothed throughout regulatory period to avoid sharp tariff variations) and the entire volume risk is born by consumers: if demand goes down and the DSO does not obtain the revenue target in one regulatory period, in the following period tariffs will be adjusted to make-up for the missing revenues in the previous period. The entire revenues in gas distribution come from "per KWh" tariff components (i.e. from rates based on distributed quantity) and from fixed monthly fee per measuring point aimed for covering fixed costs related to reading, measuring, calibration etc.

2.3. Determination of cost of service parameters

Assets are included into RAB ex-ante. After expiry of the reg. period CAPEX is revised and the difference between planned and real values (positive or negative) is shifted to the following reg. period, whereas CAPEX overruns are recovered only up to an efficient margin. The ex-post assessment is planned for 2017.
A simplified benchmarking method was applied to define allowed base OPEX (for year T-2) for each of 36 DSOs. The benchmark was performed separately on a few segments of OPEX and simultaneously took into account following outputs:

- Energy delivered through the distribution network
- Number of consumers connected
- Length of distribution network

The Agency plans to perform benchmark analysis based on some of the recognized methods (DEA, COLS, SFA, etc.) in 2015/16 and to apply results/efficiency factors for the 2nd regulatory period.

Exceptional rate revision could be carried out during the regulatory period in case of unexpected changes in the market that have a significant impact on the gas distribution activity and that DSO could have not anticipated, prevented, eliminated or avoided. The approach to determining key cost of service parameters are summarized in the following table.

Differences between actual and allowed (revised) revenues are summed to a special account and shifted to the next reg. period - tariffs are increased or decreased so that the account is brought back to zero (no threshold).

Table 216: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue cap
Regulatory asset base	Net book value
Capital expenditure	Planned value subject to ex-post assessment
Approach to operating expenditure	Benchmarking and revenue cap revision
Form of capital remuneration applied	Pre-tax nominal WACC
Additional revenue items (where applicable)	Excess losses in exceptional cases

The concession lease is covered as an OPEX. Also, in case DSO is not owner of the network, OPEX include the cost of the network rent.

The weighted average costs of capital (PPTK) before taxation is calculated in the following way:

$$WACC = \frac{r_E}{1-P} \cdot \frac{E}{D+E} + r_D \frac{D}{D+E}$$

Where:

- r_E = rf + β x MRP is the cost of equity
- MRP is the Market Risk Premium
- r_D is the cost of debt
- P is the corporate tax rate
- E is equity capital
- D is debts
- rf is the return on risk-free investments [%]
- β is the variability coefficient of return on energy operator's shares in relation to average variability of return on all shares quoted on the market.

The debt leverage is set at a target ratio considered as efficient by the regulator (D/E ratio 50/50% defined by the Methodology). There is no adjustment ex-post.

3. Tariffs for distribution services

The tariff structure is based on tariff item for the distributed gas quantity and fixed monthly fee for covering the corresponding part of fixed expenses of gas distribution related to a metering point.

3.1. Distribution tariffs

The regulator is in charge of setting the distribution tariffs for a regulatory period (based on allowed revenues) after distribution companies submit their requests or after the regulator initiates a tariff setting process

Allowed revenue for each year of regulatory period is allocated to two tariff items:

- tariff item for the distributed gas quantity (kn/kWh)

- fixed monthly fee for covering the corresponding part of fixed expenses of gas distribution which are related to a metering point (kn).

Both of the tariff items are set for 12 tariff models[84] (derived according to yearly gas consumption).

Tariff item for the distributed gas quantity is calculated by using coefficients of consumption and fixed monthly fee is calculated by metering point.

Values of those coefficients are prescribed by the Methodology in the corresponding ranges of values for each tariff model, and DSOs submit them to the Regulator in their tariff requests.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 217: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included in distribution tariffs (up to allowed level of 3%)
Presence of uniform tariffs	No
Presence of non-linear tariffs	No
Presence of regulated retail tariffs	For households only, temporary
Presence of social tariffs	Under preparation

There are currently 35 DSOs in the country and each DSO charges different tariffs corresponding to its allowed revenues. The energy related component is different for each DSO, whereas the fixed monthly fee is the same for all DSOs. Tariffs are equal for all customers of the certain tariff model in the whole distribution area of a DSO (post-stamp principle). There are no further differentiation or nonlinearities.

Distribution tariff includes the cost of losses. The maximum value of allowed quantity of gas for covering losses that is recognised in allowed revenue is 3% of gas entering the distribution system.

On an exceptional basis it may be justified to approve a greater amount of allowable losses, taking into account the specificities of business conditions and the characteristics

[84] From 1 Jan 2014

of the distribution system, whereby the operator is obliged to submit an operational plan for reducing gas losses that is feasible within a reasonable time.

End-user tariffs are regulated for households only and on a temporary basis. A mechanism for support to vulnerable customers is currently being created at State level.

3.2. Connection and capacity issues

The connection fee consists of:

- Connection construction cost

- Cost of preliminary/final works

- Cost of the regular creation of technical conditions in the distribution system or cost of the extraordinary creation of technical conditions in the distribution system (on case by case basis).

The cost of the regular creation of technical conditions exists only for DSOs for which a regulatory account (special long-term incentive model for Greenfield or significant investments) has been established by the Regulator. For the rest of DSOs the regular creation of technical conditions is covered by the distribution tariff.

There are 4 categories of connections to the distribution system:

- Category I - connection of the building with a connection capacity determined by energy conditions in an amount less than or equal to 100 kWh/h,
- Category II - connection of the building with a connection capacity determined by energy conditions in an amount higher than 100 kWh/h and less than or equal to 400 kWh/h,
- Category III - connection of the building with a connection capacity determined by energy conditions in an amount higher than 400 kWh/h and less than or equal to 4000 kWh/h
- Category IV - connection of the building with a connection capacity determined by energy conditions in an amount higher than 4000 kWh/h.

The connection fee is generally based on a shallow approach. The deep approach is applied only when the cost of regular creation of technical conditions in the distribution system (applies to 4 out of 35 DSOs) or the cost of extraordinary creation of technical conditions in the distribution system is charged. This exists only for DSOs for which a special long-term incentive model for greenfield or significant investments has been established by the Regulator.

Connection charge segments are calculated as follows:

- Connection construction cost - according to market conditions, i.e. client is free to procure the necessary works from a DSO or from a different source certified by DSO;
- Cost of preliminary/final works - standard costs approved by the regulator;
- Cost of the extraordinary creation of technical conditions in the distribution system - according to prepared study, on case by case basis;
- Cost of the regular creation of technical conditions - standard costs per kW approved by the regulator.

The DSO is allowed to refuse access to the system to third parties:

1. When there is lack of capacity

2. When access to the system would prevent DSO from performing a public service obligation

3. When access to the system could cause serious financial and economic difficulties for DSO considering "take or pay" contracts concluded prior to the application for approval of access.

In case of refusal of access to the system, DSO must deliver to the third party a decision with reasons for denying access, and afterwards third party can file a complaint to the Regulator.

The Regulator must issue a decision within 60 days since the filing of the appeal. The decision of the Regulator is executive, and the injured party can initiate an administrative dispute against the Regulator's decision.

Also, DSO which refuses access to the system because the lack of capacity or other justifiable reason must, within a reasonable time, make the necessary enhancements in the system in order to allow access to the system, if they are economically feasible or if potential user is willing to finance those enhancements of the system.

Key issues in the setting of connection charges are set out in the table below.

Table 218: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Mostly shallow. Deep if special investment required (4/35 DSOs)
	Methodology adopted	Standard or market cost
Hosting capacity	Scope to refuse connection	Yes
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	Yes. The DSO has the duty to enhance capacity in case this is a reason to reject connections.

4. Distribution system development and operation

Decisions are taken by DSOs, which have an obligation to supply all customers

The distribution system development plan is prepared for the regulatory period and submitted to the regulator for approval, in line with DSO's request for determination of the amount of tariff items for gas distribution.

The plan must include a feasibility study of the planned investments, including a projection of the gas supply and demand, a projection of the schedule for connecting system users, and the financing sources for the planned investments. These analysis are not public.

Table 219: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Approved by regulator and published
Key responsibilities for its development	DSO
Degree of integration with renewables plan	N.A.
Relationship with consumption trends	Explicitly taken into account
Relationship with quality of service targets	No explicit connection
How trade-offs between network development and alternative technologies are treated	The network development plan reports only the decisions of the DSOs. The analysis, on which those decisions are based, are not public.
Requirements to integrate cost benefit analysis	No. Only feasibility study required with demand and supply scenarios

Pursuant to the Act on Gas Market, DSO's duty is to provide attention to energy efficiency and the protection of nature and environment. Accordingly, distribution network plan has to tend and to enable system development in a way to align with current environmental policies.

General Conditions for Gas Supply (Official Gazette No. 158/13) prescribe general standards as well as guaranteed standards of quality of gas supply. Quality of service parameters are planned to be implemented starting from 2nd regulatory period. Providing optimal quality of gas supply will be encouraged through incentives (revenue formula) and reimbursement for services provided outside of the guaranteed standards, both starting from 2nd reg. period (1 Jan 2017)

4.1. Metering

DSO owns the meter after have invested in meter replacement or have the responsibility of the economic management of the connection, including meter, in case the investor of the connection was the customer. In both cases, DSOs have full responsibility for metering.

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 220: Key approach to metering

Issue	Approach adopted
Discos role in metering	Full responsibility
Monopoly services in the metering	Yes, but customers can choose another provider of the meters
Smart metering functionality	N.A.

There are pilot projects planned for the deployment of smart meters.

Information about the features of such meters is not available to the Agency.

By the end of 2014 the Agency is planning to launch the procurement procedure for the preparation of the methodology for analysing the costs and benefits of introducing advanced measuring devices in the field of gas.

The share of consumption by non-daily metered end customers connected to distribution system is 88.4% (2013).

Country Report – Hungary (electricity distribution)[85]

1. Overview of to the distribution sector

In Hungary operates six legally unbundled DSO, covering the whole territory of the country. The main responsible of the definition of the distribution tariff is the NRA, with some recommendation and principles defined by the government.

1.1. Institutional structure and responsibilities

In *Hungary* there are 6 distributors supplying electricity to 5.5 millions of customers covering the whole country. Each of the 6 DSO´s are mainly owned by foreign investors through their respective parents companies. Total energy distributed in 2013 amounted to ca. 37 Twh.

All DSO´s in Hungary are by legal unbundling in accordance with the rules of unbundling laid down in the Electricity Act basis of Directive 2003/54/EC. Otherwise there are no special rules for the DSO with less than 100,000 customers.

Table 221: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 customers	Exemption *	Share of total demand
Country	6		6	0	N/A	N/A
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 222: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges

[85] Pending validation from the NRA.

DSO			
Government – Ministry of National Development		Defines main principles	X
NRA	X	X	X

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The main responsible of the definition of the distribution tariff is the NRA, with some recommendation and principles defined by the government.

Until the 1st of October 2014, the responsibilities for the definition of connection charges are split between the Ministry of National Development and the NRA (Hungarian Energy Office). Since the 1st of October 2014, the NRA is going to be responsible for the whole process.

1.2. Key figures on revenue and tariffs

Distribution revenues in 2013 were 274 billion HUF (920 Millions of Euros), broken down by the following activities:

- Operation expenditure – 89 billion HUF- 304 Millions of Euros (33%)
- Depreciation – 65 billion HUF- 221 Millions of Euros (24%)
- Capital Cost – 50 billion HUF – 165Millions of Euros (18%)
- Network loss – 69 billion HUF - 230 Millions of Euros (25%)

In Hungary, there are 5 classes of consumers according to the voltage level, but some level have some particularities in Medium and Low voltage connections:

- High voltage Connection point higher than 35 kV
- High/medium voltage. Connection higher than 1 kV
- Medium voltage connection
- Medium/low voltage connection
  - Profile based, all day. With contracted capacity not exceeding 55,2 kW or 3x80A
  - Profile based, controlled
  - Not profile based. With contracted capacity exceeding 55,2 kW or 3x80 A
- Low voltage connection
  - Profile based, all day. With contracted capacity not exceeding 55,2 kW or 3x80A. The residential customers supplied by the Universal Service Providers belong to those categories.
  - Profile based, controlled. The residential customers supplied by the Universal Service Providers belong to those categories.
  - Not profile based. With contracted capacity exceeding 55.2 kW or 3x80A.

Each tariff has the following components:

- Basic charge. A per connection component for all consumers, equal for all consumers in the same class. (HUF/connection point/year)

- Capacity charge. A per KW charge based on the contractual maximum withdrawal power (enforced via the meter), for consumers with HV, HV/MV transformation, MV connections, and for not profile based MV/LV transformation and LV consumers HUF/kW/year).
- Energy charge. A per kWh charges equal for all consumers in the same class - (HUF/kWh)
- Distribution reactive power charge. For all consumers except consumers with controlled meters (MV/LV transformation and LV), if the meter installed can measure the reactive power (this charge represents only a very small part of the DSO's income). (HUF/kVa rh)
- Distribution loss charge. A per kWh charges equal for all consumers in the same class (HUF/kWh)
- Distribution time schedule balancing fee - A per kWh charges equal for all consumers in Profile based in MV/LV connection and LV connection. (HUF/kWh)

A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 223: Tariff components, customers and revenues per customer class

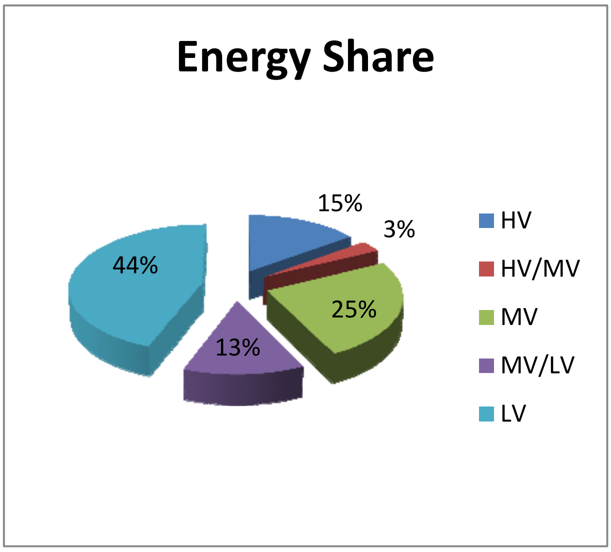
Customer classes	Tariff components	Connection points (Based in 2012 data)	Total of electricity delivered (MWh)	Revenue (€)
HV	Basic charge, Capacity charge, Energy charge, Reactive power charge and Loss charge	135	5050000	16778720
HV/MV	Basic charge, Capacity charge, Energy charge, Reactive power charge and Loss charge	98	9479000	166787833
MV	Basic charge, Capacity charge, Energy charge, Reactive power charge and Loss charge	6111		
MV/LV (Profile based settlement, all day)	Basic charge, Distribution time schedule balancing fee, Energy charge, Reactive power charge and Loss charge	21353	19428000	737305018
MV/LV (Profile based settlement,	Basic charge, Distribution time schedule balancing fee, Energy charge, Reactive power charge			

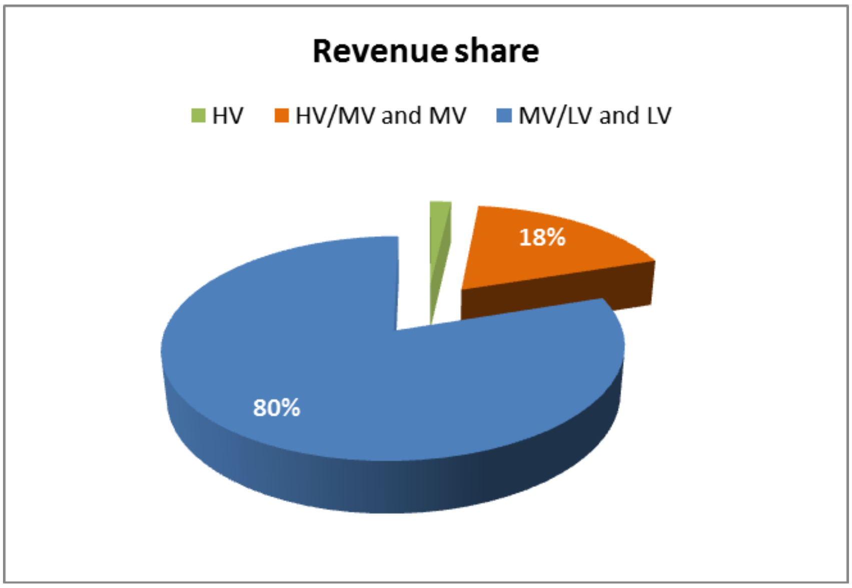
controlled)	and Loss charge			
MV/LV (Not profile based settlement)	Basic charge, Capacity charge, Energy charge, Reactive power charge and Loss charge			
LV (Profile based settlement, all day)	Basic charge, Distribution time schedule balancing fee, Energy charge, Reactive power charge and Loss charge	7225209		
LV (Profile based settlement, controlled)	Basic charge, Distribution time schedule balancing fee, Energy charge, Reactive power charge and Loss charge			
LV (Not profile based settlement)	Basic charge, Capacity charge, Energy charge, Reactive power charge and Loss charge			
Total	-	7259906	33957000	920871572

Average HUF / eur rate 2013: 296.8730 HUF/Eur

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 51: Proportion of energy accounted by customer categories





Revenue share information by voltage level is not available.

There is not official definition of typical consumer or consumer group in Hungary.

The typical network tariff in 2013 for House Hold, small and large industrial customers is illustrated below:

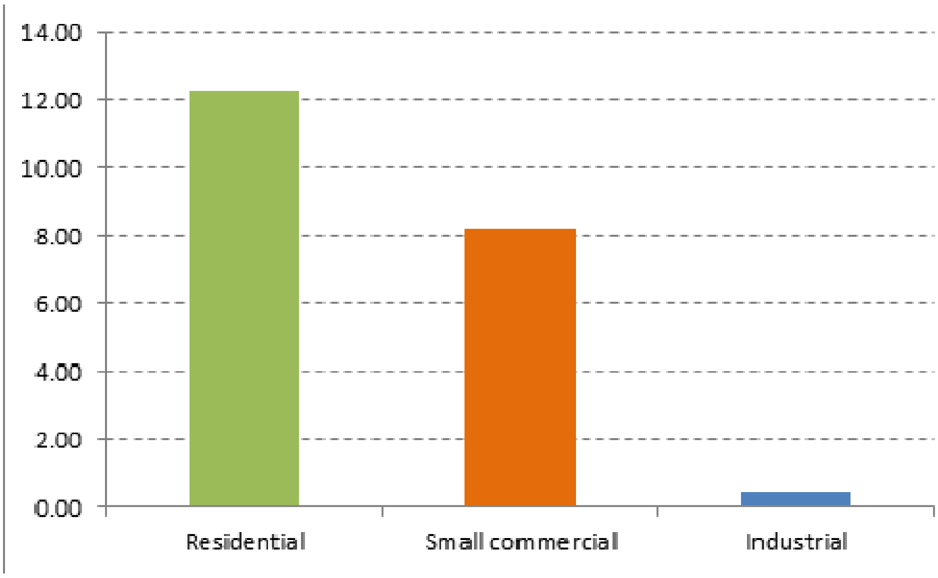
Table 224: Breakdown of annual charges – typical customer types, 2013 (HUF)

Customer type	Notional Energy usage	Fixed charges (Basic charge)	Fixed charges (Capacity charge)	Energy charges	Loss Charges	Time schedule balancing fee	Demand and reactive charges	Total (includes: Basic, Energy , Loss & Time charges)
Households	3500 kWh	1,446 HUF/year	Not applicable	30030 HUF (8,58 HUF/kWh)	10325 HUF (2,95 HUF/kWh)	1260 HUF (0,36 HUF/kWh)	3,67 HUF/kVArh	4,061 HUF
Industrial LV (MV/LV transformation voltage)	50MWh	3516 HUF/year	Not applicable	294500 HUF (5,89 HUF/kWh)	96000 HUF (1,92 HUF/kWh)	8640 HUF (0.36 HUF/kWh)	3,67 HUF/kVArh	402656 HUF
Industrial VHV	24000 MWh	210912 HUF/year	1464 HUF/kW-	5520000 HUF (0.23	4560000 HUF (0,19	Not applicable	2,19 HUF/kVAr	10290912

			Year	HUF/kWh)	HUF/kWh)		h	

The resulting average tariffs per kWh are illustrated below. These include the Basic fixed charges, Energy Charges, Loss Charges and Distribution Time schedule balancing fee. These not includes Capacity charges and reactive charges.

Figure 52: Average network charges (HUF/kWh), 2013



2. Regulation of distribution activities

The distribution networks operators are regulated under a licence regime. An incentive based revenue cap model is form of regulation is applied.

2.1. General overview

The Act LXXXVI of 2007 provides the main rules of the whole Electricity market, including the distribution activities. According to article 29, the responsibilities of DSO´s shall include: “Operating the network covered by the operating licence in a seamless and safe manner, serving all market operators in a competitively neutral manner, transmitting electricity to users, operating, maintaining and, if necessary, developing the distribution network of the given area”.

In addition to the duties referred to in paragraph before, the DSO´s shall ensure the long term ability of the distribution network to meet reasonable demands for the distribution of electricity.   The DSO´s must be in possession of the network, system and operation control, and tariff metering and information technology equipment necessary for its activities.

The NRA (Hungarian Energy Office) main responsibilities is consumers protection is strategic markets: Electricity, Natural GAS, District Heating and Water, “Providing regulated access to networks and systems, carrying out regulatory competencies in order to maintain security of supply and fostering competition”.

The distribution sector is regulated under a licence regime. An incentive based revenue cap model is form of regulation is applied. The regulation is primarily based on the asses on the cost side, but there is a penalties system to ensure quality standards.

Key features of the regulatory regime are set out in the following table

Table 225: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Licence
Duration of tariff setting regime	4 years
Form of determination (distributor propose/regulator decide)	Regulator decides
Scope for appeal regulatory decision	No

2.2. Main incentive properties of the distribution regulatory model

The NRA is responsible for the definition of the allow revenues. All costs are assessed in details once in every 4 years. After a cost review justified operational costs, regulatory asset base, cost of capital and costs of losses are indexed with an (inflation-X) type method. There are different inflation indices for the different cost elements (e.g. CPI for the operational costs).

To determine next year’s (T) tariffs, justified revenues are divided with T-2 year’s quantities, reducing quantity risk of DSOs.

The following key regulatory incentives apply for the DSOs:

- Since allowed revenues of the DSOs are indexed following an inflation-X based rule for 4 years, the DSOs are incentivised to reduce costs.
- In addition, Cost of losses (quantity and price) are supervised yearly. When justified cost of losses is less than the real value, the regulation reimburses only a part of the difference to the DSO.
- There is also a penalties system in connection with the service quality. Automatic compensations (price discount) are granted to consumers in case some quality standards are not met.

At the same time the following tools are provided to mitigate risks:

- Energy consumption: To mitigate risk of energy consumption reduction and their impact in next year’s tariffs, justified revenues are divided with T-2 year’s quantities. This way The DSO´s are reducing the risk by decreasing consumption.

- Cost of losses: when justified cost of losses is less than the real value, the regulation reimburses a part of the difference to the DSO.

The regulator sets the required (minimum) values for quality of service standards and the DSOs have to meet these standards. The regulator monitors the DSO's quality of service values. There are 4 elements (3 at DSO level, 1 at consumer level) that quality services interact with the system tariff:

- During a cost review: a bonus-malus system in connection with the service quality
- An interim obligatory price discount if the DSO doesn't fulfil a quality standard,
- During price indexation: a bonus-malus system in connection with the service quality,
- Automatic compensations are granted to consumers in case some quality standards are not met. The cost of those compensation is not included in the allowed returns of the DSOs

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 226: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue Cap model
Regulatory asset base	The value of the asset base is based on a re-evaluation process, so the regulatory asset value replaced all DSO's book asset values. Every year the value of the DSO´s assets are update with the net of investments. The update of the DSO´s assets are indexed by a price index of "investment goods" (Publishes by the central statistical office".
Capital expenditure	n.a.
Approach to operating expenditure	The justified costs of the DSOs are calculated with benchmarking the different DSO activities. The average activity cost. The DSO better than the average receives only its own costs, the DSO doing worse receives only the average
Form of WACC applied	Real, pre-tax WACC
Additional revenue items (where applicable)	Not applicable

The following formula is applied in determining the real-pre-tax WACC:

$$WACC = \frac{E}{D+E} \times \frac{K_E}{(1-t_e)} + \frac{D}{E+D} \times K_D$$

Where:

- K_E = Rf + β MRP is the cost of equity
- Rf is the risk free rate (based on historic German state bond data, and USA data)
- β is based on international regulatory practice
- MRP is the Market Risk Premium (based on historic German and USA data)
- K_D is the cost of debt based on Hungarian and international data and international regulatory practice
- t_e is the corporate tax rate (the rate is given by the Hungarian law)
- D/E is the ratio of debt to equity, the base year has been set to 60 % in favour of debt

The debt leverage (Ratio E/D) is set at a target ratio considered as efficient by the regulator based on the sector's real data, international regulatory practice, and historical Hungarian regulatory debt leverage values. There is no adjustment ex-post.

The regulation formula includes the "X-component" in the revenue cap. To calculate the "X-component", the regulator keeps in account the international experience and past performance of the company.

3. Tariffs for distribution services

3.1. Distribution tariffs

The regulator is in charge of setting the distribution tariffs (based on allowed revenues).

The following approach is adopted to allocate costs between customer categories with the following key features:

- Distribution justified costs are split into fixed and variable costs (estimation based on the DSO's data).
    - Fixed costs are assigned to each voltage levels and are covered with a per connection point base charge (a minor part of fixed costs is covered with the HUF/kWh public lighting charge).
    - Variable costs are allocated to voltage levels (estimation based on the DSO's data).
- Then, on each voltage levels costs are split and allocated to be covered with per kWh, per kW (and per kVArh) charges
- The cost of losses is similarly allocated to per kWh charges of the different voltage levels.

The details of distribution tariff by voltage class and their components are summarized in section 1.2 Key figures on revenue and tariffs.

Tariff components can be downloaded from here (in English): http://www.mekh.hu/en/regulated-prices/electricity.html. A direct link for the distribution tariffs valid since 1st November 2013 (Excel): http://www.mekh.hu/gcpdocs/51/System%20use%20tariffs%202013%20nov.xlsx

Various other aspects of distribution tariff setting are summarized in the table below.

Table 227: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Distribution losses is a component of the distribution tariff system
Presence of uniform tariffs	Yes, the same tariff for the same voltage level in the country
Presence of non-linear tariffs	No, all tariff components are linear No tariff components differentiated according to time of use.
Presence of regulated retail tariffs	
Presence of social tariffs	No

According to the decree of the Hungarian Energy and Public Utility Regulatory Authority, generators connected either to the transmission or the distribution grid have to pay (principally) TSO/DSO tariffs, but the value of these tariffs for generators is 0 HUF/kWh.

There are not special incentives in network tariffs for large users like power plants.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 228: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Connection charges are shallow (or rather shallow) first of all for small consumers at Low voltage.
	Methodology adopted to determine connection costs	Standard charges and rules set by the regulator for smaller consumers (LV, MV). For larger consumers or generators the DSO makes an estimation based on its cost, but the client is free to procure the necessary works from a different source.
Hosting capacity	Scope to refuse connection	The DSO´s may refuse connection to the distribution network at any specific connection point due to technical reasons. The DSO´s, when refusing connection to the distribution

		network, expressly specify the conditions under which connection may be authorized, and offer another connection point, if the necessary technical facilities are available or can be provided. The regulator, at the network user's request, conducts an inquiry concerning the refusal of the access. If the access was refused in violation of the statutory provisions referred to the regulator adopts a resolution to compel the DSO affected to allow access to the distribution network. Where network access is provided under the conditions set out in the regulator’s resolution, the network user is liable to pay the access charges specified in the regulator’s resolution.
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	No, the DSO is assumed to have a duty to connect all the capacity that applies for connection. For exemptions (refusing connecting consumers) see above.

The connection fee is set by the Hungarian Energy and Public Utility Regulatory Authority. The charges are to be paid in the case of:

- New connection to the public network, or
- Increasing capacity demand.

Generators have to make an individual agreement on connection charge with the network licensee (connection charge = max. 100 % of the value of activated assets installed for connecting the generator to the public network) or to install the assets necessary for connection on their own (agreement with the network licensee is necessary).

Consumers have to pay:

- Connection standing charge,
- Charge for installing connecting wire or cable,
- Charge for installing public line.

4. Distribution system development and operation

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 229: Approach to distribution planning

Issue	Approach
Form of distribution planning document	There is not a Distribution network plan submitted to the regulator. DOS´s has to facilities a network development plant to the TSO.
- Key responsibilities for its development	Not applicable
- Degree of integration with renewables plan	There is no published plan but the licensees own plans are in relation with the renewable generation targets.
- Relationship with consumption trends	There is no published plan but the licensees own plans are in relation with other targets.
- Relationship with quality of service targets	There is no published plan but the licensees own plans are in relation with the quality of service targets.
- How trade-offs between network development and alternative technologies are treated	Actually there are not smart grid deployment.
- Requirements to integrate cost benefit analysis	Not applicable. However cost-benefit analyses are used to select the network investments.

Each DSO according Act LXXXVI of 2007 on electricity, have to drawing up a network development plan annually and submitting it to the transmission system operator according to the procedure laid down in the Operating Code.

Thus, Licensees have their own development strategy for distribution network but there is no separated development plan submitted to the regulator. The distribution lines with the rated voltage of 132 kV are the part of National Development Plan (NDP) for transmission lines which is submitted to the regulator every year. NDP is published for the public.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 230: Approach to distribution planning

Issue	Approach

Requirements for dispatch of renewable plants connected to DSO network	The DSO can only require larger embedded units to disconnect in case the distribution system cannot host their injections
Possibility to dispatch flexible loads	Flexible loads are all only controlled by the system operator or self-dispatched
Other sources of flexibility open to DSO	There is no storage function on distribution networks.

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 231: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs have full responsibility for metering and for the installation, calibration and maintenance of metering. They shall provide for the collection and processing of metering data and for forwarding such data to the electricity suppliers.
Monopoly services in the metering	Yes
Smart metering functionality	Final implementation of Smart meter is still in progress. There is no final decision on deployment of Smart metering system. The smart meters should have basic functions. a) quarter-of an hour measurement b) remote reading

There are not smart meters massive installed at Hungary.

Country Report – Hungary (gas distribution)[86]

1. Overview of to the distribution sector

The main stakeholders in the distribution tariffs are the DSOs, the Governance and the NRA.

Natural gas distribution systems are operated by 10 regional distributors, five of them being predominant and dividing up the entire territory of the country among themselves (which have more than 100000 customers each).

The customer classes are classified by the size of the gas meters and not by theirs

1.1. Institutional structure and responsibilities

In Hungary there are 10 regional DSO, five of them being predominant and diving up the territory of the country among themselves. DSO´s are supplying gas to approximately 3,06 million of customers with a gas network of 82018 km.

The five large DSO are completed legally unbundled in 2007. DSO´s with less of 100000 consumers must be accounting unbundled. Summary data on industry structure is set out below.

Table 232: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	10	The majority of the DSOs are owned by retailers For the DSOs with more than 10000 consumer it is obligation to use legal unbundling	5	5	n.a.	1,3% of total demand is supplied by small DSO with less than 100.000 consumers
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

The responsibility for setting distribution tariffs is spread between the following jurisdictions

[86] Pending final validation from the NRA.

- The DSO
- Government (through the Ministry of National Development)
- The NRA (Hungarian Energy Office; the main responsibilities are consumer protection, providing regulated access to networks and systems, carrying out regulatory competencies in order to maintain security of supply and fostering competition)

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 233: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Provides data for the calculation	-	-
Government	Puts in place the rules for determining the allowed revenue	-	-
NRA	X	X	X

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adopted to setting distribution tariffs involves the following steps:

1. The framework for the setting and regulation of use-of-system charges and the general rules for the application of charges shall be laid down by the Minister in a decree adopted on the basis of the proposal of the Office

2. The Office shall consult the authorised operators concerned and representative customer advocacy groups. The Office shall publish its proposal for the decree on its website by 15 May of the year preceding the beginning of the new price regulation cycle, and it shall submit request the minister to promulgate the proposal by way of decree.

3. The minister shall adopt or reject the proposal of the Office within thirty days of the submission thereof.

   (a) If the proposal is adopted, the minister shall promulgate by way of decree the framework for the setting and regulation of use-of-system charges and the general rules for the application of charges within thirty days after the adoption of the proposal of the Office.

   (b) If the proposal is rejected, the minister shall publish his reasoned rejection within fifteen days after adopting the decision on the rejection of the proposal.

4. The use-of-system charges set by the Office in a decision shall be treated as maximum prices. By way of derogation from the maximum price, lower non-discriminatory prices may be applied, provided that such prices are published in advance.

5. Use-of-system charges shall be regulated in four-year price regulation cycles. Before the beginning of each price regulation cycle, the Office shall review costs, and it shall use the outcome thereof to set use-of-system charges.

1.2. Key figures on revenue and tariffs

Distribution revenues in 2013 were 82.636.740.981 HUF, No further slit by service is available.

Customer categories are defined by the size of their gas meters and not by their consumption:

- Below 20m3 / h
- 20-100 m3 / h
- 100-500 m3 / h
- Above 500 m3 / h

Information on available tariff components and the number of customers in each category is set out in the table below.

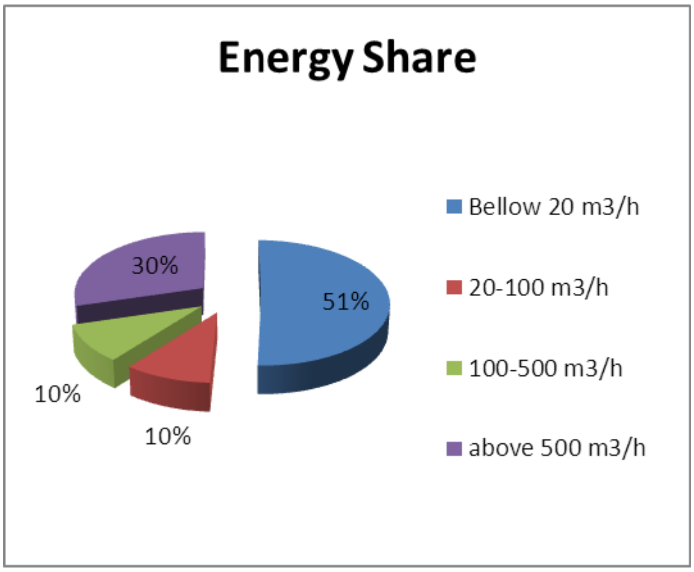
Table 234: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Energy delivered (MWh)	Revenue €
Below 20m^3 / h	Fixed: Standing Fee Variable: Commodity charge	3037496		
20-100 m^3 / h	Fixed: Standing Fee Variable: Commodity charge	16767		
100-500 m^3 / h	Fixed: Capacity Fee Variable: Commodity charge	3026		
Above 500 m^3 / h	Fixed: Capacity Fee Variable: Commodity charge	490		
Total		3057779	74847608	278357213

Currency rate Average 2013: 296.8730 HUF/EUR

The breakdown of energy volumes by customer category are set out in the charts below. The information about revenues by category is not available.

Figure 53: Proportion of energy by category



The tariff structure has two components:

- Fix component covering costs which do not depend on the volume flown(Standing fee or Capacity fee)
- Variable component covering costs which are strongly related to the flown amount (Commodity charge)

The typical network tariff for segments of consumers (Residential, Small industries, Large Industrial) is not available.

2. Regulation of distribution activities

The distribution sector is regulated under a licence regime. A "cost-reimbursement" form of regulation is applied.

2.1. General overview

The GAS supply GAS Supply Act XL of 2008 provides the rules of the whole gas market, including the distribution activities. The role of the DSO is to operate, develop, and maintain the distribution lines of natural gas to ensure high level of systems secure, reliability and quality. DSO must facilities data to services providers and to the regulators and government agencies.

DSO requires licenses to operate and shall:

- Majority ownership of the operated distribution line.
- Measurement and data transmission tools

- Data communication and information technology system to support of data with system and transmission operators
- Cooperate with the connected system operators, premises based service providers and system users in order to ensure the development and operation of the interoperable natural gas system

The NRA (Hungarian Energy Office) main responsibilities is consumers protection is strategic markets: Electricity, Natural GAS, District Heating and Water, “Providing regulated access to networks and systems, carrying out regulatory competencies in order to maintain security of supply and fostering competition”.

The distribution sector is regulated under a licence regime. A “cost-reimbursement” form of regulation is applied.

Key features of the regulatory regime are set out in the following table

Table 235: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	The regime which Hungarian natural gas market is based is by licence
Duration of tariff setting regime	Use of system charges shall be regulated in four year price regulation cycles
Form of determination (distributor propose/regulator decide)	The framework for the setting and regulation of use of system charges and the general rules for the application of charges shall be laid down by the minister in a decree adopted on the basis of the proposal of the Office
Scope for appeal regulatory decision	No such legislation is in place.

2.2. Main incentive properties of the distribution regulatory model

The implanted Hungarian model does not have any incentives.

At the same time the following tools are provided to mitigate risks:

- Annual revenue reconciliation
- Adjustment of the volume every year using the *day degree corrected* with the actual consumption of the previous year this way the system compensates for the change in volumes
- Yearly correction if the inflation exceeds a certain threshold
- Extraordinary tariff review to compensate for big unexpected changes in the market environment
- Ex-ante approval of capex by the NRA
- Quality of service factor

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 236: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue CAP regulation
Regulatory asset base	Based on the revaluation of the book value of the DSOs assets. This asset base is indexed after the revaluation.
Capital expenditure	CAPEX are separately approved by NRA
Approach to operating expenditure	OPEX is revised at the start of each regulatory period when the NRA undertakes a cost and asset review to determine the cost level for the period
Form of WACC applied	Nominal Pre-tax
Additional revenue items (where applicable)	There are no additional revenue items

WACC is recalculated at the beginning of every regulatory period after updating its parameters. The following formula is applied in determining the WACC:

$$WACC_{pre-tax} = \frac{E}{E+D} \times \frac{R_E}{(1-T)} + \frac{D}{E+D} \times R_D$$

Where:

- E: equity
- D: Debt
- T: corporation tax
- R_E: Cost of equity before taxation, calculated according to the formula:

$$R_E = R_F + \beta \times (R_M - R_F),$$

Where:

- R_F: Real risk free rate
- β: Equity beta
- $(R_M - R_F)$: is the overall equity risk premium
- R_D: cost of debt, calculated according to the formula:

$$R_D = R_F + \sigma$$

- A: debt premium

No further information is available. Criteria for the calculation of parameters are not published.

3. Tariffs for distribution services

The NRA is in charge of setting the distribution tariffs through a methodology. The tariff is composed by a fix and a variable part, being all the cost associated to the distribution costs.

3.1. Distribution tariffs

The costs are allocated to tariffs in the following way:

- First the cost base is determined for each DSO with the help of the cost and asset review
- Next, the costs are split up between consumption categories
- Following this, the cost in each category are split up into fix and variable part
- If there are corrections necessary it is done in this phase
- And finally the fix cost are divided by the corresponding quantities and variable costs are divided by the day degree corrected volumes

Various other aspects of distribution tariff setting are summarized in the table below.

Table 237: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	There is not charged in the tariff as a consequence of distribution losses
Presence of uniform tariffs	There is not a uniform tariff. There is a regional tariff for each DSO. Also there is a reduced capacity fee for consumers who have consumption in the summer period but do not consume in winter.
Presence of non-linear tariffs	All tariff components are linear
Presence of regulated retail tariffs	In general, the tariffs are regulated between system operator and system user, but not end consumer. There is an exception for the above because in case of consumers consuming under universal supply the regulated price incorporates the distribution charges so in this case there is an indirect regulation for the retail prices
Presence of social tariffs	There is not social tariff

There are no additional components included in the distribution tariff except distribution costs. The distribution losses are not charged in the tariff. The tariffs are published in the tariff decree.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 238: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Shallow(er) charges for small and medium-sized consumers, too. Above the DSO level the cost are spread between the consumers. The reinforcements are covered mainly through the system usage tariffs; however in some cases the charges for big consumers contain the development of the TSO system.
	Methodology adopted	The NRA set the methodology by publishing the decree. Therefore the DSOs apply the methodology and calculate accordingly the separate connection costs/charges. If the consumer has any problem with the calculated connection charge, the proposal could be revised by the NRA. If fixed charges would be set the DSO only applies the prices.
Hosting capacity	Scope to refuse connection	There is a specific option for the DSO to refuse the connection in that case if the connection cost per consumption factor is really high (for instance: small future consumption goes with expensive investment cost).
	Requirements to publish hosting capacity	No requirement on the DSO to publish hosting capacity information. But the DSO is required to notify to the regulator the technical capacity of his network in order to the NRA gets familiar with these data
	Targets and/or incentive schemes to enhance hosting capacity	The current regulation dose not applies any incentives

4. Distribution system development and operation

In the current regulation the DSOs do not have to provide a network development plan. Investment projects are assessed individually as they come up.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 239: Approach to distribution planning

Issue	Approach
Form of distribution planning document	N/A
- Key responsibilities for its development	N/A
- Degree of integration with renewables plan	N/A
- Relationship with consumption trends	N/A
- Relationship with quality of service targets	N/A
- How trade-offs between network development and alternative technologies are treated	N/A
- Requirements to integrate cost benefit analysis	N/A

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 240: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	They have to comply with the overall quality standard and with the DSOs technical criteria.
Possibility to dispatch flexible loads	No
Other sources of flexibility open to DSO	No

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 241: Key approach to metering

Issue	Approach adopted
DSO role in metering	The DSO owns the gas meters and it has the obligation for reading the gas meters. The DSO is also obliged to provide the traders with their respective metering data.
Monopoly services in the metering	The DSOs are monopolists in metering activities
Smart metering functionality	There are several ongoing pilot projects. There is not information about his functionality

There are ongoing pilot projects but no data is currently available about smart metering.

Country Report – Ireland (electricity distribution)

1. Overview of to the distribution sector

The distribution sector in Ireland is concentrated in a single state owned statutory monopoly that has a permanent licence to operate as DSO. An incentive based model is used for distribution regulation.

1.1. Institutional structure and responsibilities

In *Ireland* there is only 1 distributor supplying electricity to roughly more than 2 million customers with an overall circuit length of 167528 km[87] . Summary data on industry structure is set out below.

Table 242: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	1	0	1[88]	0	No	%
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

The responsibility for setting distribution tariffs is spread between the following jurisdictions (for example):

- The DSO
- The NRA (Commission for Energy Regulation - CER)
- Government (Department of Communications, Energy and Natural Resources)

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

[87] Eurelectric, Power Distribution in Europe – Facts & Figures, 2013.
[88] The DSO is owned by the former vertically integrated state owned electricity company. However, it has legal and functional independence from its parent. The parent company still owns supply and generation facilities.

Table 243: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges	Regulated services
DSO	Also involved	Calculates for NRA approval	Calculates for NRA approval	N/A
Government	Defines main principles			N/A
NRA	X	X	X	N/A

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adopted to setting distribution tariffs involves the following steps:

- The CER issues a public consultation on tariff
- The CER approves the tariff methodology
- The DSO calculates the tariff based on the allowed revenue
- The CER approves the tariff based on the approved revenues.

1.2. Key figures on revenue and tariffs

Distribution revenues in Ireland in 2013 were €729 million. No further split by service type or number of customers is available.

2. Regulation of distribution activities

2.1. General overview

The role of the DSO in Ireland is to builds, operates and maintains a nationwide electricity distribution system, connect customers and provide metering services. ESB Networks Ltd, as the only DSO is a state owned statutory monopoly that has a permanent licence to operate as DSO. ESB Networks Ltd is a separate company within ESB.

CER's primary economic responsibilities in energy are to regulate the Irish electricity and natural gas sectors. The overall aim of the CER's economic role is to protect the interests of energy customers, maintain security of supply, and to promote competition in the generation and supply of electricity/natural gas. It also has functions in customer protection by resolving complaints that customers have with energy companies. Other CER's competencies are safety regulation of electrical contractors, gas and LPG installers and gas pipelines and safety regulation of upstream petroleum safety extraction and exploration activities.

An “incentive-based” form of regulation is applied.

Distribution tariffs are not itemised in final retail tariffs for either gas or electricity. Customers see a Standing Charge and a Unit Price (plus applicable environmental levies-electricity) and VAT.

Key features of the regulatory regime are set out in the following table

Table 244: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Licence.
Duration of tariff setting regime	Allowed revenues are assessed for five year revenue control periods. Within each five year period allowed revenues are assessed annually and the corresponding tariff component is updated accordingly.
Form of determination (distributor propose/regulator decide)	Distributor proposes, regulator approves
Scope for appeal regulatory decision	Not available

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- As the revenue is set for a five year period the DSO is also incentivised to reduce costs.
- Expenditures are reviewed for efficiency and the DSO is at risk to have costs disallowed that the NRA decides were not efficiently expended. There is a cap on the incentive (and penalty) that the DSO can achieve. Where the DSO underspends compared to the allowed Opex or Capex and that amount is not due to efficiency gains, the DSO is required to pay back that amount (or have it offset against revenue allowed in the following year).
- Performance targets are set by the CER for the DSO. These targets are set for quality of supply, electrical losses and customer service.
- Incentives for connecting renewable generation.
- Adjustment factor where inflation in any year does not match the inflation forecast in the 5 year projection

At the same time the following tools are provided to mitigate risks:

- Opex is fixed for a five year period. If the DSO spends more than it is allowed, it bears the cost. On the other hand if the DSO spends below what it is allowed it can keep the surplus made any one year for a period of five years as a means of incentivising efficiency.
- Revenue and expenditure are reviewed annually and compared to forecast. Deviations from forecast may be corrected by an annual adjustment factor for reduced revenue or higher than expected costs.

- An allowance is made in the forecast revenues for expected increases in numbers of customers each year and there is an annual adjustment factor to allow for a larger or smaller number of new customers in that year.
- The regulator will consider any major event that impacts the DSOs profitability during the annual revenue review.

Key components of quality of service regulation are:

- Incentive mechanisms on quality of service: the incentives relate to continuity of supply, improving service to 'worst served customers', improving customer satisfaction, incentives to reduce electrical losses, incentives for meter reading. Allowed revenues are increased (decreased) if the DSO performs better (worse) than the predefined targets for each of the quality of service criteria.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 245: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue cap
Regulatory asset base	The CER uses a replacement cost approach, it uses acquisition cost, indexed with inflation, as a proxy for the replacement cost
Capital expenditure	Capital Asset Pricing Model (CAPM) and the Weighted Average Cost of Capital (WACC). Primarily as part of the five yearly price control process and also the annual revenue review, the CER review the capital expenditure and investments made by the DSO. CER does not approve specific projects but approves an overall capital expenditure amount following submission of the DSO's planned capital programme for the forthcoming five year period. The DSO makes a submission to the regulator as part of the 5 year price control. This submission is reviewed by the regulators technical consultants to check if the proposed expenditure is necessary and efficient.. The review uses a review of the DSO's historic expenditures from the previous price control period to assist in assessing the need and efficiency of the DSO's proposed capital expenditure and includes efficiency requirements.
Approach to operating expenditure	Review of the DSO's historical operational

	expenditure to assess whether the DSO"s expenditure has been incurred efficiently while delivering the expected benefits for customers in line with the package agreed as part of the previous price control determination.
Form of capital remuneration applied" (WACC real, nominal, ten years Treasury bond + adder, …)	Real, pre-tax cost of capital
Additional revenue items (where applicable)	N/A

As part of the price control, CER's consultants review the efficiency of capital expenditure from the previous price control period. However, no express "utility" review of individual investments is undertaken. CER is entitled to request such a review and could exclude the investment from the regulated asset base. Although some operating expenses have been disallowed in the past for not being efficient, no capital investments have been disallowed, that I am aware of.

Benchmarking is used in the setting of the five year price control period. Benchmarking is conducted against best international companies in this field. A sample of areas of the DSO's functions is selected each year for comparison where appropriate examples from DSOs in other jurisdictions can be identified and costs identified.

The following formula is applied in determining the WACC:

$$WACC = r_E \cdot \frac{E}{D+E} + r_D \frac{D}{D+E}$$

Where:

- rE is the cost of equity
- rD is the cost of debt
- E and D are the total values of equity and debt respectively used to determine the level of gearing in the company, so giving the relative weights between the cost of equity and debt finance.

Allowed revenue is based on certain assumptions including

- GWh
- No of consumers connected
- Quality of service

Assumptions are updated annually.

The CER has used a notional gearing level and a forward looking cost of debt as used in the WACC calculation. The level of net debt is set based on a historic cost RAB i.e. this assumes that the DSO has only conventional debt and only efficiently incurred expenditure has been added to the RAB

The X factor is used to smooth out the allowed revenue over the period so consumers are not faced with volatile tariffs and also to ensure that the DSO has sufficient cash to meet its requirements over the p rice control period.

3. Tariffs for distribution services

Capital and operating costs are allocated across different system levels and then divided by the number of customers in each level. All consumers are charged a distribution tariff including a per KWH charge and an annual standing charge. A combination of standards costs and client specific connection fees are used. The DSO cannot refuse reasonable requests of connections, it can only enforce a waiting list in the case of generators.

3.1. Distribution tariffs: additional issues

The DSO calculates the tariff and the CER approves it. Tariffs comprise five elements:

- Fixed Charge per month
- Energy Charge per kWh consumed
- Capacity Charge per kVA of MIC
- Maximum Import Capacity Penalty
- Power Factor Penalty KVArh

Capital and operating costs are allocated across different system levels and then divided by the number of customers in each level.

There are ten distribution tariff groups. The categories of distribution groups are listed in the document “rules for application of duos tariff group” which can be found at this link: http://www.esb.ie/esbnetworks/en/commercial-downloads/Rules-for-Application-of-DUOoS-Tariff-Groups.pdf

All consumers are charged a distribution tariff including two components

- A per KWH charge
- An annual standing charge.

There is an element of time differentiation. There is a day/night tariff.

The current distribution charges can be found at this link (pages 18-22): http://www.esb.ie/esbnetworks/en/commercial-downloads/ESB-Networks-Statement-of-Charges.pdf?v=2014

Various other aspects of distribution tariff setting are summarized in the table below.

Table 246: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Distribution Losses are charged for separately. Distribution Loss Adjustment Factors (DLAFs) are applied to the metered consumption of relevant customers to apportion distribution losses to energy consumption or production metered at end user sites.
Presence of uniform tariffs	For domestic customers there is a separate urban and rural tariff category. Urban domestic connections are defined as domestic connections that are fed from three-phase overhead or underground LV network. Rural domestic connections are defined as domestic connections that are fed from single phase overhead network.
Presence of non-linear tariffs	All tariff components are linear
Presence of regulated retail tariffs	No
Presence of social tariffs	No

Embedded generators pay "Generator Distribution O&M Charges" to cover ongoing O&M on the connection asset and facilities added for reinforcement. Renewable generation support is funded via an additional tariff component of the retail tariff.

A decision was made to rebalance distribution tariffs in favour of large energy users. The savings for large energy users were to be funded by a rebalancing of domestic network tariffs. The amount of savings for large energy users was to be €50million per year.

3.2. Connection and capacity issues

Consumers and small customers generally pay a once off fee – larger connection feeds can be paid installations – this is agreed with the DSO.

Key issues in the setting of connection charges are set out in the table below.

Table 247: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Charges are shallow for small connections. Larger connections are required to pay a contribution towards network reinforcements.
	Methodology adopted	A combination of standards costs and client specific connection fees are used. Contestability is available for distribution connections.
Hosting capacity	Scope to refuse connection	For consumers the DSO cannot refuse reasonable requests of connections. For generators the DSO cannot refuse connection but it can enforce a waiting list
	Requirements to publish hosting capacity	None
	Targets and/or incentive schemes to enhance hosting capacity	None. However, the DSO provides its proposed capital expenditure programme and the network connection scenarios on which its proposed capital expenditure is based. CER and its advisors assess the appropriateness of the DSO's connection scenarios and forecasts.

4. Distribution system development and operation

System development is decided by the DSO and the development plan is notified to the NRA. Renewable generation targets, consumption trends and quality of trends targets are taken as inputs in the distribution development plan. The DSO can require larger generators to disconnect in cases of system security. The mass rollout of smart meters is not expect to commence until 2018

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 248: Approach to distribution planning

Issue	Approach
Form of distribution planning document	
- Key responsibilities for its development	Network development plans are normally notified to the regulator but they are not published
- Degree of integration with renewables plan	Renewable generation targets are set by the Government only at national level. These targets are taken as an input in the distribution development plan. The development plans pursue the objective of

	creating hosting capacity consistent with the national plan.
- Relationship with consumption trends	The DSO takes a range of factors into account when proposing its distribution network plan. They will include items such as the national spatial development plans, national economic forecasts etc.
- Relationship with quality of service targets	There is no express link between the distribution network plan and the quality of service targets. However, the DSO will take quality of service targets into account when developing the distribution plan because of the incentives/penalties attached to the quality of service targets
- How trade-offs between network development and alternative technologies are treated	Not treated
- Requirements to integrate cost benefit analysis	The DSO conducts internal cost-benefit analyses of network development investments proposed by its staff when deciding which ones to include in its capital expenditure proposals to CER. However, CER does not normally review those CBAs.

The DSO publishes a strategy document which describes its approach to network development. The document can be find at: http://europe.nxtbook.com/nxteu/zahra/esb_networks2027/#/0

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 249: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	The DSO cannot dispatch any generators. Only the TSO can dispatch some distributed connected generators. The DSO can require larger generators to disconnect in cases of system security.
Possibility to dispatch flexible loads	Only the TSO can dispatch flexible loads.
Other sources of flexibility open to DSO	None

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 250: Key approach to metering

Issue	Approach adopted
DSOs role in metering	DSOs have responsibility for metering and own the meter
Monopoly services in the metering	DSOs are monopolists in metering activities

Smart metering functionality	• Half hourly measurement/ Daily Polling • Remote reading • Remote reconnection/disconnection of customers

The Smart Metering Programme is entering Phase 3 “Detailed Design”. The mass rollout of smart meters is not expect to commence until 2018. The plan is to roll out 2,2million smart meters to residential electricity customers and 200000 to Small and Middle Enterprises (SME).

Country Report – Ireland (Gas distribution)

1. Overview of to the distribution sector

The distribution sector in Ireland is concentrated in a single semi-state company which operates the distribution of natural gas. The regulation regime in place involves several components of "incentive based regulation".

1.1. Institutional structure and responsibilities

In *Ireland* there is 1 distribution system operator supplying gas to 657000 customers with a gas network of 11160 km lower pressure distribution pipelines.

Prior to Ireland's implementation of Directive 2009/73/EC (concerning common rules for the internal market in natural gas), Gaslink (i.e. Ireland's gas TSO & DSO) operated as the Independent System Operator (ISO) under the Second Energy Package and forms part of the semi-state company Bord Gáis Éireann (BGÉ).

Gaslink is responsible for the operation and planning of Ireland's gas transmission and distribution system, which is owned by Bord Gáis Éíreann (i.e. Ireland's gas Transmission & Distribution Asset Owner). In order to facilitate Gaslink in carrying out its role, an Operating Agreement was signed between BGÉ and Gaslink, and approved by the National Regulatory Authority, Commission for Energy Regulation (CER).

Under the Operating Agreement, BGÉ through its division Bord Gáis Networks (BGN) carries out works at the direction of Gaslink in respect of the development, maintenance and operation of BGÉ's network. With reference to Directive 2009/73/EC, the CER received an ITO application from BGE in 2012. Following a review of the ITO application, the CER issued its preliminary decision (in March 2013) with respect to BGÉ ITO certification application. In May 2013, the CER received the European Commission Opinion with respect to the certification of BGÉ as an ITO. Taking utmost account of the EU Commission's opinion, the CER decided (in July 2013) to grant BGÉ preliminary certification as an ITO, subject to the completion of all outstanding ITO items identified in the CER's preliminary certification decision. The rationale for the delay in full ITO certification was due to the impending sale of BGÉs energy business (Bord Gáis Energy), which would result in BGÉ becoming Fully Ownership Unbundled (FOU). Specifically, the CER was of the view that the imposition of a full ITO model, with costs such as for rebranding, would impose unnecessary transaction costs on BGÉ in the likely event that BGÉ became FOU by 2014.

In December 2013, the Irish Government confirmed that a preferred bidder (i.e. a consortium involving Centrica plc, Brookfield Renewable Energy and Icon Infrastructure) was selected for the purchase of Bord Gáis Energy. This sale was completed on the 30th of June 2014.

The outcome from the sale will result in BGÉ becoming a networks only company (with Gaslink being re-integrated back into BGÉ), which will result in BGÉ becoming certified as Full Ownership Unbundled (FOU) under Directive 2009/73/EC At present, BGÉ is working towards FOU certification, and it is envisaged that an application will be submitted to the CER in the coming months.

Summary data on industry structure is set out below.

Table 251: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 customers	Exemption*	Share of total demand(DSOs <100000 customers)
Country	1	0	1	0	NA	0%

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**

The regulator carries out a review of the distribution allowed revenue every 5 years. The review which is in force at the moment is "Price Control 3" (PC3), which covers the period from October 2012 to September 2017.

The responsibility for setting distribution tariffs is spread between the following jurisdictions:

- The DSO
- The NRA (Commission for Energy Regulation - CER)
- Government (Department of Communications, Energy and Natural Resources)

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 252: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges	Regulated services
DSO	Calculates for NRA approval	Calculates for NRA approval	Calculates for NRA approval	NA

Government	Grants powers via primary law.	Usually not involved[89]		NA
NRA	Sets rules, approves[90]	X	X	NA

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adopted to setting distribution tariffs (Price Control Process) involves the following steps:

- DSO sends a submission to the CER on its business plan and revenue requirements; this includes demand forecasts.
- The CER analyses this submission
- The CER issue a consultation
- The CER decides on an annual allowed revenue for the five years ahead, with the aim of providing incentives for DSO to seek out efficiencies.

1.2. Key figures on revenue and tariffs

Distribution revenues in gas year 2013/2014 were € 185.2 million, broken down by the following activities:

- Distribution 70%
- Metering 20%
- Other 10%

A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 253: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenue
Daily Metered	€cent/pk day kWh, c/kWh	220	NA
Non Daily Metered	€cent/pk day kWh, c/kWh	NA	NA
Total	-	Ca. 657000	NA

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

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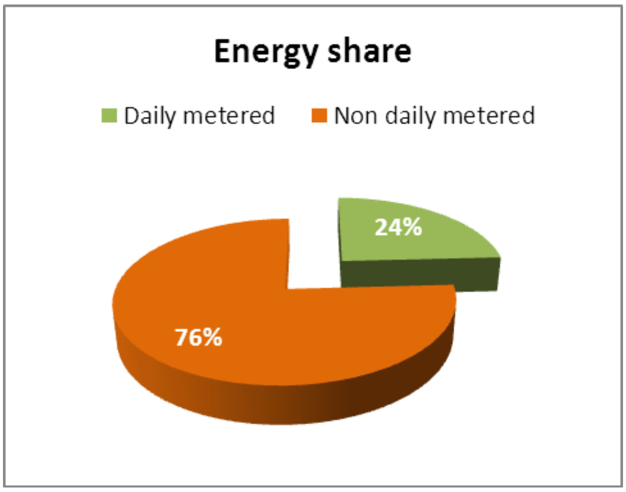
89 The Department has no role in tariff setting unless a Ministerial policy is issued to the regulator.
90 Sets out allowed revenues via the Price Controls.

Figure 54: Proportion of energy accounted by customer categories



Customer categories are defined by Supply Point Annual Quantity for each connected site in MWh:

- ≤ 73 MWh
- > 73 MWh ≤ 14653 MWh
- > 14653 MWH ≤ 57500 MWh
- > 57500 MWh

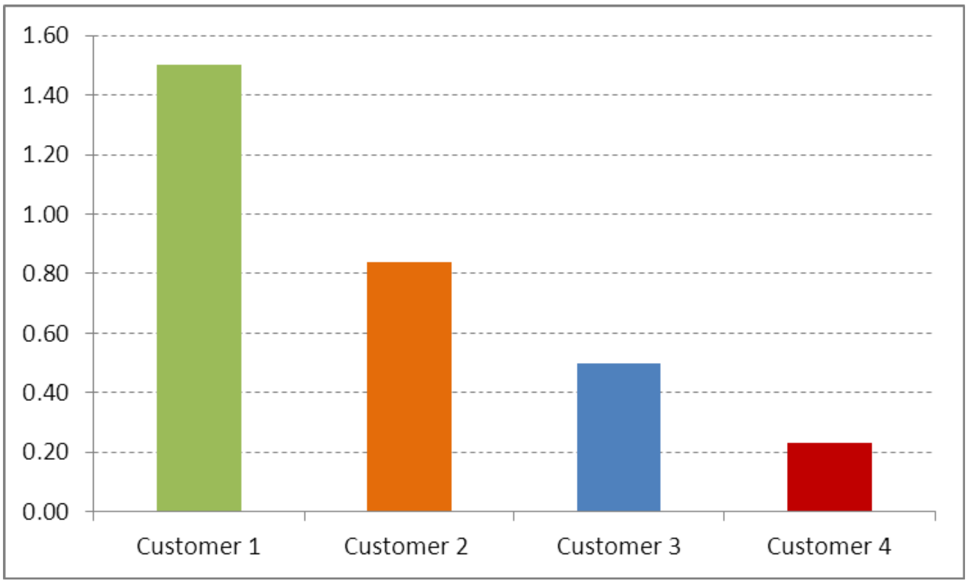
Using tariff information from Gaslink's website and applying this to notional customer types, illustrative tariffs are shown below in Table 4. However, it should be noted that these notional customer categories are not necessarily representative of typical Irish gas customers.

Table 254: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Customer Maximum Daily Quantity	Capacity Charge	Commodity Charge	Total
Customer 1	50 MWh	0,37 MWh	572,82	178,9	751,72
Customer 2	10000 MWh	54,79 MWh	66349,88	17450,2	83800,08
Customer 3	40000 MWh	182,56 MWh	158042,81	41755,04	199797,85
Customer 4	80000MWh	313,11 MWh	132206,94	52080	184286,94

The resulting average tariffs per kWh are illustrated below.

Figure 55: Average network charges (€cent/kWh), gas year 2013/2014



An example of network tariffs applied in 2013, by BGN DSO is included as Annex 1.

As reported by CER, the average annual distribution network cost for an average household is approximately €230[91].

2. Regulation of distribution activities

2.1. General overview

The role of the DSO in Ireland is to operate, develop and maintain a system for the transmission and distribution of natural gas being a system that is both economical and efficient, ensure the safety and security of the transmission, distribution and supply of natural gas.

CER's primary economic responsibilities in energy are to regulate the Irish electricity and natural gas sectors. The overall aim of the CER's economic role is to protect the interests of energy customers, maintain security of supply, and to promote competition in the generation and supply of electricity/natural gas. It also has functions in customer protection by resolving complaints that customers have with energy companies. Other CER's competencies are safety regulation of electrical contractors, gas and LPG installers and gas pipelines and safety regulation of upstream petroleum safety extraction and exploration activities. More recently, the CER was also appointed as economic regulator for water services in Ireland.

[91] Based on an average usage of 13,800 KWh.

The distribution sector is regulated under a licence regime. A mix of "cost-reimbursement" and "incentive-based" form of regulation is applied.

Distribution tariffs are not normally itemised in final retail tariffs for either gas or electricity. Customers see a Standing Charge and a Unit Price (plus applicable environmental levies) and VAT.

Key features of the regulatory regime are set out in the following table.

Table 255: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Licence[92]
Duration of tariff setting regime	5 years (from October 2012 to September 2017)
Form of determination	distributor propose/regulator decide
Scope for appeal regulatory decision	Not available

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs: -

- Revenue Cap regime
- An efficiency factor of 1% is applied for certain items as part of the Price Control decisions.
- The DSO may keep 50% of underspend pass through costs in certain circumstances.

At the same time the following tools are provided to mitigate risks:

- Tariffs are revised annually and are to recover the Allowed Revenues as set out for that particular year of the Price Control. There is discretion to re-profile revenues within the Price Control period. Revenues were re-profiled as part of the 2013/14 Transmission tariffs.
- The WACC that is applied is subject to a floor and ceiling of 5,2% and 8,2%. This is triggered automatically when market rates change significantly. This ensures the benefits are passed onto consumers annually or conversely that financial risk of the DSO is not carried forward if market conditions deteriorate.
- Ex ante approval of all investments is required. This includes both those set out in the Distribution Price Control and in certain instances where a new town is connected under the Connections policy the capex is added to the Regulated Asset Base ex ante as well.

Key components of quality of service regulation:

- Quality of service regulation has no impacts on tariffs;
- The DSO performance is monitored as part of the licence conditions;

[92] While any party may seek a licence to own or operate a distribution network, at present Gaslink is the only participant in that market.

- Each year Gaslink publishes a Performance Report detailing KPIs for the year;
- The regulator has powers via an energy customer section to impose charter payments to gas customers where appropriate (when the DSO is found to be in breach of its customer charter code of practice);
- If necessary a direction from the CER would be given to the DSO where the quality standards are not reached.

2.3. Determination of cost of service parameters

The regulator along with external consultants assess the DSO submission. There is use of benchmarking vis-à-vis other systems, in particular GB distribution companies. The DSO is benchmarked as part of the Price Control review.

The approach to determining key cost of service parameters are summarized in the following table.

Table 256: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Mixture of fixed cost reimbursement controlled via Price Controls and pass through costs adjusted on an annual basis. Certain pass through costs have an incentive mechanism where controllable.
Regulatory asset base	Replacement value updated to consider inflation (from Central Statistics Office)
Capital expenditure	Overview of the DSO historic and forecasted CAPEX.
Approach to operating expenditure	Overview of the DSO historic and forecasted OPEX
Form of capital remuneration applied"	Not available
Additional revenue items (where applicable)	Not available

The formula applied in determining the WACC is not available. To determine the WACC, the regulator adopts the Capital Asset Price Model (CAPM).

3. Tariffs for distribution services

Revenues are recovered via an 80:20 Capacity: Commodity split. Capacity charges are based on expected peak day withdrawal. Commodity based flows charges are based on actuals.

The DSO values the Net Present Value (NPV) of a new connection in order to connect new towns.

3.1. Distribution tariffs: additional issues

The CER is in charge of setting the distribution tariff (based on allowed revenues).

Revenues are recovered via an 80:20 Capacity: Commodity split. This applies to the entire Distribution network which is maintained at 16 bar, and 4 bar for service pipelines. Capacity charges are based on expected peak day withdrawal. Commodity based flows charges are based on actuals.

There are 4 categories of customers-with difference volume ranges.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 257: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Shrinkage costs are socialised across all network users. Shippers are responsible for balancing their portfolio and the DSO also procures gas for balancing purposes.
Presence of uniform tariffs	Tariffs are postalised
Presence of non-linear tariffs	The natural log element of the tariffing regime is non-linear. In other words tariffs increase as customers get smaller and because of the natural log effect (ln) this increase is not linear(i.e. directly proportional) with the change in size.
Presence of regulated retail tariffs	The last remaining regulated domestic tariff was abolished from 1t July 2014 as the criteria for deregulation had been met.
Presence of social tariffs	No

3.2. Connection charges

Connection charges are based on Industrial & Commercial connections (Large, Medium and Small) and Domestic (One off, new housing, non-gas estates, local authority housing). Also included are mixed developments.

Key issues in the setting of connection charges are set out in the table below.

Table 258: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Both
	Methodology adopted	Standard costs and costs specific to projects as well as based on a cost per metre of pipeline.
Hosting capacity	Scope to refuse connection	Net Present Value (NPV) of a new connection must be positive to connect new towns. If a party wishes to connect it must pay upfront connection charges which are partially determined by the length from the gas mains. This discourages requests beyond reasonable distances. The DSO always attempts to meet reasonable requests for connections. What generally arises is that a so called "New Town" is connected where the NPV is positive. An anchor load (large factory etc.) is required in general.
	Requirements to publish hosting capacity	The DSO is required to notify to the CER the technical capacity of the network for Price Control mechanism purposes. Unlike transmission there is no annual report setting out the technical distribution network capacity.
	Targets and/or incentive schemes to enhance hosting capacity	

4. Distribution system development and operation

System development is decided by the DSO and supervised by the NRA through the examination of the development plan for transmission and distribution grids. The NRA is working on facilitating the use of Compressed Natural Gas (CNG) and biogas injection at the distribution level.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 259: Approach to distribution planning

Issue	Approach
Form of distribution planning document	
- Key responsibilities for its development	There is no development plan published for the distribution network. Any CAPEX for the network is laid out in the Price Control and the DSO updates the regulator on progress. This would then be an input into the setting of the annual distribution tariffs. A Network Development Plan (NDP) is only required for the Transmission system and data from this applies to the distribution system too. Gaslink, as TSO is obliged to publish the NDP and the CER is responsible for examining the ten-year network development plan and facilitating a public consultation on its contents.
- Degree of integration with environmental policies	There is an innovation fund focusing on Compressed Natural Gas (CNG) which is progressing. In addition the regulator is working towards facilitating biogas injection at the distribution level. These issues are outlined in the NDP.
- Relationship with quality of service targets	A Separate Performance Report is published that outlines service targets and performance.
- How trade-offs between network development and alternative technologies are treated	Not treated
- Requirements to integrate cost benefit analysis	The NDP outlines the projects that will be realized (as per the Price Control) and those that may be required over the reporting period.

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 260: Key approach to metering

Issue	Approach adopted
DSOs role in metering	DSOs have full responsibility for metering, and these meters are on the Regulated Asset Base.
Monopoly services in the metering	DSOs are monopolists in metering activities
Smart metering functionality	Not yet decided, currently CER is heading up the Smart Metering Program which is ongoing[93].

A dynamic load profiling model is used to define ex ante the consumption level of each Non Daily Metered (NDM) point.

[93] The CER, working with the Department of Communications, Energy and Natural Resources (DCENR), established Phase 1 of the National Smart Metering Programme (NSMP) in late 2007. Phase 1 included a plan to conduct a nationally representative smart metering trial in order to assess the costs and benefits of smart meters and to inform decisions relating to the full rollout of an optimally designed universal National Smart Metering Programme. Phase 2 is the requirements capturing phase of the programme. CER is currently conducting extensive stakeholder engagement and consultation to inform the optimal smart metering solution. Source: http://www.cer.ie/electricity-gas/smart-metering.

Country Report – Italy (electricity distribution)

1. Overview of to the distribution sector

DSOs belong to vertically integrated groups. For DSOs which have 100000 customers or fewer, functional separation obligations are not in place.

The regulator is responsible for setting the level of allowed revenues and for specifying the tariff structure to be used by DSOs.

1.1. Institutional structure and responsibilities

In Italy there are 151 distributors supplying electricity to around 27 million customers. Summary data on industry structure is set out below.

Table 261: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	136	-	All	126	Embedded generators do not pay distribution tariffs	3%

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**

In most cases DSOs belong to vertically integrated groups (they have legal separation). Accounting and functional separation obligations are enforced. As for brand and communication policy separation, a consultation is currently pending within a wide review of functional separation.

For DSOs which have 100.000 customers or fewer, functional separation obligations are not in place. Such DSOs provide around 3% of the country´s electricity, to a customer base which is also around 3% of the total population.

The responsibility for setting distribution tariffs is spread between the following jurisdictions (for example):

- The DSO provides data to the regulator on their costs and quality levels

- The NRA issues the tariff methodology (for allowed revenues, tariff structure and connection charge) and quality of service regulation, after wide public consultation with all stakeholder
- Government defines the high-level principles for tariff regulation, through primary law

For the regulatory period 2012-15, the regulator issued 3 consultation papers for tariff regulation and 3 consultation papers for quality of service regulation of DSOs. All submission received during each consultation phase were published in the regulator's website and RIA reports have also been published.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 262: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Provides the regulator with data on its cost and quality levels	Provides the regulator with data on its cost and quality levels	Provides the regulator with data on its cost and quality levels
Government	Defines main principles	Defines main principles	Defines main principles
NRA	Issues the allowed revenues	Issues the tariff structure	Issues the connection charges

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

1.2. Key figures on revenue and tariffs

Distribution revenues in Italy in 2013 have not been made publicly available.

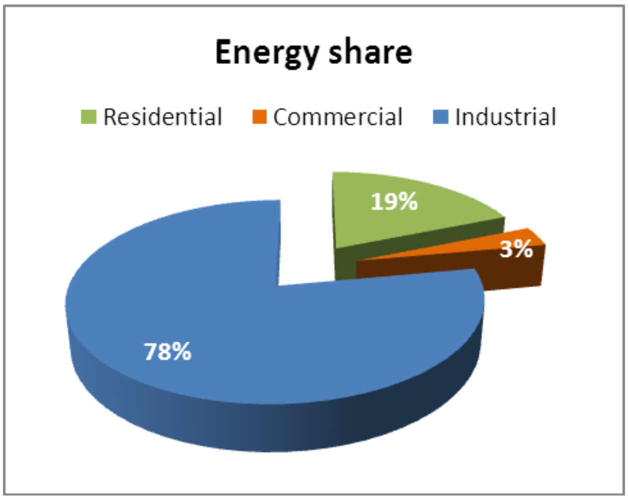
Information on available tariff components and the number of customers in each category is set out in the table below.

Table 263: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers
Household	KWh, KW, charge per withdrawal point	29427000
All others (non-household)	KWh, KW, charge per withdrawal point	7672007
Total	-	37099007

The breakdown of energy volumes by customer category are set out in the charts below.

Figure 56: Proportion of energy and revenue accounted by customer categories



The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below:

Table 264: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Demand and reactive charges	Total
Residential	3500kWh	6	17	118	141
Small commercial	50MWh	7	639	184	820
Industrial	24000MWh	563	12784	42480	55827

Household user connected to a low voltage network with an annual consumption of 3,500 MWh and 6 kW of contractual power.
Small Industrial connected to a low voltage network, an annual consumption of 50 MWh and 20 kW of contractual power.
Large industrial user with an annual consumption of 24000 MWh, 7000 use hours and 400 kW of contractual power.

As can be seen from the table above, tariffs have three components: a withdrawal point charge, a rated power charge, and a per-unit energy charge. Tariffs are differentiated by voltage level, wherein the ´residential´ customer voltage level is 3 kW; the ´small commercial´ voltage level is from 16,5 kW to 20 kW; the ´industrial´ voltage level is a maximum of 400 kW.

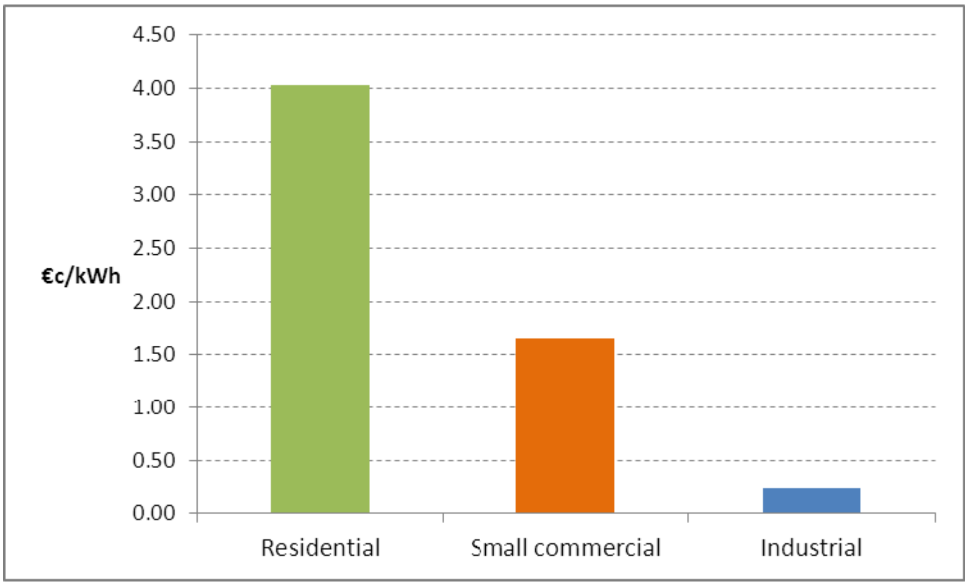
It should be noted that the calculated values for the distribution tariff of the residential customer shown above also includes the tariffs for transmission. The distribution and transmission tariffs are not typically separated.

It should also be noted that two other components are accounted for within the tariffs for the residential customer (that is, included within the values shown above), specifically:

- A quality of service component; and
- A cost compensation mechanism for the various DSOs.

The resulting average tariffs per kWh are illustrated below.

Figure 57: Average network charges (€cents/kWh), 2013



2. Regulation of distribution activities

There is cost-reimbursement of CAPEX and a number of input-based and output-based incentives are used within the regulatory regime. OPEX is limited by a price cap. Quality of service targets are in effect.

Concessions are tendered for a 30 year period

2.1. General overview

The distribution sector is regulated under a mixed regulatory regime. A "cost-reimbursement" form of regulation is applied for CAPEX incurred by DSOs. In addition, a number of both "input-based" and "output-based" incentives apply for priority investments (including pilot projects for smart grids) as well as for service quality. Operating costs are subject to a price cap system.

Key features of the regulatory regime are set out in the following table

Table 265: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession regime
Duration of tariff setting regime	4 years (there are some suggestions to extend this to 6 years)
Form of determination (distributor	Distributor provides data on its costs, etc.,

propose/regulator decide)	and the regulator sets the allowed tariffs based on cost-reimbursement (CAPEX) and a price cap (OPEX)
Scope for appeal regulatory decision	Appeals may be made at the Regional Administrative Court (TAR, Lombardia) and, as a second stage, at the Council of State

Concessions are tendered for a period of 30 years by the Ministry of economic development. The current concessions have not been allocated through competitive mechanisms.
According to the law, when concessions are renewed, non-depreciated assets are expected to be remunerated on the basis of their replacement cost.

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Price caps on operating costs
- Standard losses are defined
- Input-based incentives apply for priority investments (including pilot projects for smart grids)
- Quality of service regulation / targets

At the same time the following tools are provided to mitigate risks.

Almost all allowed revenues are calculated using “withdrawal points” as the unit of measurement (i.e., allowed revenue is expressed in euro/connected customer). The only exception is revenues for distribution to public lighting systems (which are still calculated in euro/kWh). The volume risk on the DSOs is fully sterilised from allowed revenues related to capital costs, through an ex-post reconciliation mechanism (*perequazione*). However, this is not the case for operational costs; given that the number of connected customers is used as the unit of measurement, this also reduces the volume risk for operational costs.

OPEX are subject to a price cap. At the beginning of a new regulatory period the new starting price is set in a way such that 50% of the efficiency gains (the difference between actual costs and allowed costs) obtained by the firm in the previous period are not transferred to consumers in the form of reduced tariffs (i.e. they may be retained by the DSO).

Lastly, in the price cap formula used for updating OPEX, a specific parameter can be introduced in the case of unforeseen and exceptional events and changes in the regulatory framework.

Key components of quality of service regulation are:

- SAIDI and SAIFI+MAIFI reward/penalty regulation
- Guaranteed standards and automatic compensations for interruptions exceeding the maximum number of interruptions allowed for MV customers
- Guaranteed standards and automatic compensations for interruptions exceeding the maximum duration of interruptions allowed by MV and LV customers
- Voltage quality: voltage drops recording obligation
- Guaranteed standards of automatic compensations for “distribution-related commercial quality” issues (including the maximum time for connections) for MV and LV customers.

Even though there is no direct interaction between the quality of service regulation and the tariff system, it can be noted that:

- As for SAIDI and SAIFI+MAIFI reward/penalty regulation, rewards (penalties) have the concrete effect of increasing (decreasing) the allowed revenues;
- As for guaranteed standards, the cost of automatic compensation paid by DSOs is not included in the allowed returns of the DSOs.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 266: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Hybrid system, partly price-cap (OPEX) and partly cost of service (CAPEX)
Regulatory asset base	Assets within the RAB are evaluated on the basis of a ‘historical revaluated cost’ approach. Every year the value of the DSOs’ assets are updated by the inflation index of the price of “investment goods”
Capital expenditure	Cost reimbursement. Efficient CAPEX costs are rolled into the asset base, and costs are revised every year
Approach to operating expenditure	Price cap, with the tariff component related to OPEX is reset every 4 years.
Form of WACC applied	Real WACC, pre-tax

The following formula is applied in determining the WACC:

$$WACC = \frac{K_E}{1-t_e} \cdot \frac{E}{D+E} + K_D \frac{D}{D+E} \cdot \frac{(1-t)}{(1-t_e)}$$

- $K_E = r_f + \beta$ MRP is the cost of equity
- MRP is the Market Risk Premium
- K_D is the cost of debt
- t is the debt tax shield
- t_e is the corporate tax rate

- r_f is the nominal rate for risk free activities and is updated every two years

The debt leverage is set at a target ratio considered as efficient by the regulator. The level of the allowed rate of return on investments is revised every two years.

At the beginning of each regulatory period, allowed OPEX are aligned to actual OPEX, net of a profit-sharing mechanism if the efficiency targets of the previous period have been met (i.e. if companies have been more efficient than what was required by the X-factor of the previous period).

The X-factor for the new regulatory period is calculated in such a way that the allowed OPEX for the first year of the next regulatory period is aligned to actual OPEX plus 50% of the efficiency gains obtained during the previous period. Efficiency gains are defined as the difference between allowed OPEX and actual costs (based on the last available final statement).

3. Tariffs for distribution services

DSOs´ allowed revenues are based on the number of customer connections a DSO has. Network tariffs are formed through three charges, including a fixed component, a capacity component, and an energy consumed component.

3.1. Distribution tariffs

In the allocation of costs between customer categories, a DSO´s allowed revenues are based only on the number of connected customers; this is in order to fully decouple DSO revenues from energy volumes.

The costs per voltage level (LV, MV and residually HV) are separately accounted for in the process of allocating distribution costs to tariffs.

The network tariff paid by final customers has a trinomial form and consists of:

- A fixed component (euro/customer)
- A component related to capacity (euro/kW)
- A variable component related to energy (euro/kW)

Some exceptions are for public lighting systems and EV recharge points, for which a monomial tariff applies (only euro/kWh).

The actual values of the components of network tariffs are articulated per customer class:

- Household (LV), currently sub-differentiated between residential (first houses) and non-residential (second houses, i.e. cottages)
- Business customers, differentiated by voltage levels (LV, MV, HV, EHV)

- Public lighting systems, differentiated by voltage levels (LV and MV)
- Public recharging of electric vehicles (LV only for the time being).

Various other aspects of distribution tariff setting are summarized in the table below.

Table 267: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Not included in tariffs
Presence of uniform tariffs	Yes
Presence of non-linear tariffs	Yes, for household tariffs
Presence of regulated retail tariffs	No
Presence of social tariffs	Yes (they act as a subsidy mechanism)

Distribution losses are not charged as a part of the distribution tariffs. Losses are made up for by requiring each balance responsible entity to deliver more power than that consumed by its loads.

Tariffs are geographically-uniform. It is a legal requirement that the same network tariff for final customers is applied throughout the country. Retail prices are not regulated.

For household customers, the distribution tariff components are not linear, but are progressive instead. The review of the structure of the network tariff paid by household customers is currently ongoing. The progressive structure currently used is going to be discontinued because it provides negative signals and incentives with regard to improving energy efficiency. As a temporary measure, a specific experimental network tariff, which is non-progressive, is in place for heat pumps.

A social tariff system is in place (known as a social bonus), warranting a tariff discount for consumers with a household income inferior to a fixed threshold. The social bonus is given to families with low income in the form of a reduction in the cost of electricity, independent of the DSO. The costs of the scheme are paid by all consumers through an overall system charge (named “As”).

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 268: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Both. Shallow charges are used for consumers and embedded generators. A mainly-shallow approach, with deeper charges, is adopted for HV network users. That is: (1) for connections of HV final customers, 50% of the costs of new infrastructures at the same voltage level for final users; and (2) for connections of HV producers, the cost of the standard solution for the work to be done with discounts for RES and CAR.
	Methodology adopted	For LV/MV connections and for RES or CAR connections, a lump sum (single) charge is defined by the regulator on the basis of the average costs of all possible solutions. It is not related to the real work to be done, in the specific case context. For HV connections, the connection charge is related to the cost of the standard solution for the work to be done. So this charge is related to the real work to be done, on the specific case-by-case basis. For the connection of generation units, for MV or HV the generator is free to procure the necessary works from a different source, under given conditions that are specified in the regulations for the connection of generators ("TICA", Testo integrato connessioni attive)
Hosting capacity	Scope to refuse connection	A DSO cannot refuse reasonable requests of connections. For generators, the DSO cannot refuse a connection but it can enforce a waiting list
	Requirements to publish hosting capacity	Yes, this must be published
	Targets and/or incentive schemes to enhance hosting capacity	The Development Plans of DSOs contain hosting capacity targets

DSOs are not required to notify the regulator of the hosting capacity of its network unless a specific request of information is issued; but DSOs are obliged to publish the level of HC in each area according to TICA regulation.

At the moment, targets for hosting capacity are not set for DSOs as part of the process of setting allowed revenues. However, output-based incentives related to HC and with smart grid deployment on a large-scale could be introduced from the next regulator period onwards.

At the moment, there is no specific regulation or scheme in place which does not hamper investment but which implies additional OPEX (such as smart grid technology, use of demand side flexibility for grid services, voltage regulation by decentralised resources, etc.).

4. Distribution system development and operation

DSOs must create system development plans, which are to be updated on an annual basis. DSOs cannot dispatch renewable generators.

DSOs are fully responsible for metering of distribution consumers. There is a very high level of smart meter installation: in 2013 there was almost complete installation of smart meters across all consumer groups in Italy.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 269: Approach to distribution planning

Issue	Approach
Form of distribution planning document	For each DSO, a distribution system development plan must be prepared, and updated annually, and published, according to legislative obligation. Each DSO should also notify its distribution system development plan to Ministry of Economic Development and to the regulator; however, the distribution plan doesn´t need to be approved by the regulator.
- Key responsibilities for its development	DSO must prepare it and notify the plan to the Government. DSO must update the plan each year.
- Degree of integration with renewables plan	The planned development of distributed generation in the distribution area is explicitly considered in the DSO development plans
- Relationship with consumption trends	The evolution of consumption in the distribution area is explicitly considered in DSO development plans, according to overall TSO forecasts, and not only for energy consumption but also taking peak power into consideration.
- Relationship with quality of service targets	The improvement of quality of service is explicitly considered in DSO development plans, with consideration also given to the improvement targets set by the regulator
- How trade-offs between network development and alternative	Some DSOs include detailed descriptions of their smart grid projects and plans in their development

technologies are treated	plans. For the time being, trade-offs between the deployments of smart grid technologies and alternative investments are not explicitly addressed, but this is likely to be incorporated in the next future.
- Requirements to integrate cost benefit analysis	No specific requirement to integrate CBA

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 270: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	Only the TSO can dispatch resources, but DSO have a role in ensuring the procedure called RIGEDI (Riduzione generazione distribuita) for system security: distributed generation resources that are connected to MV distribution grid are required to be curtailable in case of TSO order, implemented through DSOs.
Possibility to dispatch flexible loads	The possible role of DSO in "new" dispatching of flexible loads has been explored in a public consultation; the final decision is still pending and might require legislative changes to be made before dispatching rights are granted.
Other sources of flexibility open to DSO	A few trials for battery storage systems are in place, even though no incentive regulation is in place for storage systems at the distribution level.

In the coming future, the regulator intends to lower the threshold for participating in the balancing market (including several ancillary services) from the current value of 10 MVA to 1 MW, thus involving many generation units connected to MV distribution grids. In this case the role of DSOs in "new" dispatching requires to be defined (see also answer to the following question).

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 271: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs have full responsibility for metering, and own the meters (except for larger generation units – in reference to each voltage level - whose meters are owned by the generation company; on

	this issue there is a consultation pending).
Monopoly services in the metering	DSOs have a monopoly on consumer-side metering; they do not have a monopoly on generation-side metering
Smart metering functionality	Interval metering: 1 hour for LV, 15m for HV and MV Remote reading Remote disconnection and reconnection of customers Remote control of the maximum power that can be withdrawn for LV meters for consumers with smaller contractual power An external device for sending real time consumption information to a local screen or computers, linked to smart meter via PLC, has been developed and tested in field. A consultation is open on this issue, according to Directive on energy efficiency Active energy/power withdrawn/injected Reactive energy/power withdrawn Measurement of voltage variations according to EN 50160 Continuity of supply (interruptions) recording

As of 2013 there was almost complete installation of smart meters across all consumer groups in Italy. A breakdown by customer category is illustrated below.

Table 272: Number of smart meters installed – by end of 2013

Customer category	Number
LV network users; up to 1 kV (typically 230-400 V)	37 million
MV network users; 1-36 kV (typically 20 kV, but other nominal voltage levels are operated as well, for instance 23 kV)	98000
HV network users; 36 kV (typically 130-150 kV, 220-380kV; in few areas also 60 kV)	1500
Total	37, 1 million

Some analysis has been undertaken of the impact(s) of installed smart meter technology within Italy, under a trial study which involved the installation and operation of advanced meters in Italian households. The meter technology had the following capabilities:

- On-screen display of current, historical and average consumption;
- On-screen display of the distribution of consumption within the household;
- Ability to limit consumption levels (set maximum thresholds);
- Monitoring of maximum power consumption;
- Measurements of individual load;
- Ability to send consumption messages to users;
- Detailed analysis of consumption or micro-generation, particularly solar PV generation; and

- Ability to make comparisons between different times of use.94

Analysis was undertaken of the impact of the installed meter technology on energy consumption of households. It was found that 66% of the trial participants reported a reduction in power consumption during the trial period, as compared against their baseline consumption (when smart metering technology was not used). Of those 66% of trial participants, an average power consumption reduction of 7% was achieved during the meter trial period.

It was also found that when the household customers with the highest levels of consumption were considered as a single group, their average power consumption saving during the meter trial period was 8%.[94]

[94] Italian Energy Authority, 2014. Received from: http://www.autorita.energia.it/allegati/docs/14/232-14.pdf

Country Report – Italy (gas distribution)

1. Overview of to the distribution sector

The NRA sets the allowed revenues for DSOs. All DSOs, regardless of their size, are subject to the same unbundling obligations.

1.1. Institutional structure and responsibilities

In Italy there are 233 distributors supplying gas to 21523072 customers. Summary data on industry structure is set out below.

Table 273: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	233	-	All DSOs	203	No charges are applied for the use of the gas network in the case of injections into the network	19,2%

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**

DSOs with less than 100000 customers are subject to the same unbundling obligations as other DSOs.

The responsibility for setting distribution tariffs is spread between the following jurisdictions (for example):

- The NRA issues a methodology and calculates the allowed revenue and the tariff parameters
- Government and Parliament issues the tariff principles in national and decree legislation

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 274: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges

DSO	Not involved	Not involved	Connection charges are defined and agreed in the concessions between DSOs and local authorities
Government (and Parliament)	Issues the tariff principles in law	Not involved	Not involved
NRA	Issues methodology, calculates allowed revenues and tariff parameters	Sets the tariff structure	Not involved

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

1.2. Key figures on revenue and tariffs

Information on the allowed revenues of DSOs is confidential and not publicly-available.

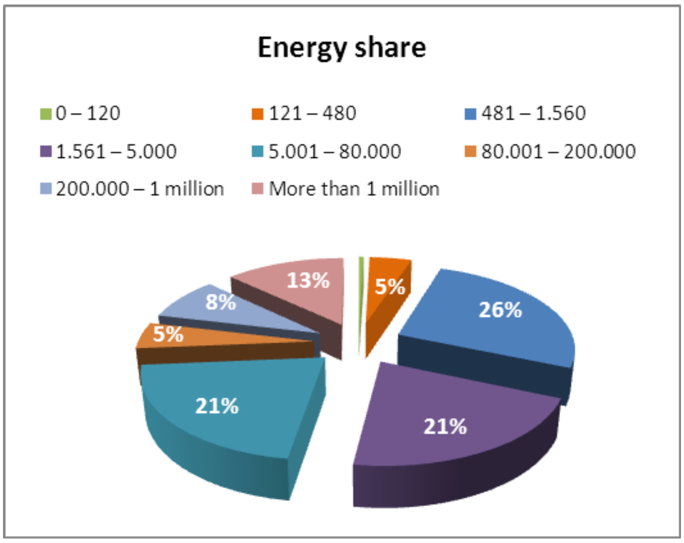
However, a breakdown of gas sales by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 275: Tariff components, customers and revenues per customer class

Customer classes (smc)	Tariff components	Number of customers	Distributed volumes (smc)
0 – 120	M3; customer class	3.650.498	172.017.292
121 – 480	M3; customer class	4.993.620	1.531.677.433
481 – 1.560	M3; customer class	9.425.240	8.851.477.466
1.561 – 5.000	M3; customer class	2.988.699	6.997.925.950
5.001 – 80.000	M3; customer class	443.267	7.150.209.474
80.001 – 200.000	M3; customer class	13.664	1.704.863.671
200.000 – 1 million	M3; customer class	6.530	2.793.467.405
More than 1 million	M3; customer class	1.554	4.334.918.894
Total	-	21.523.072	33.536.557.585

The breakdown of energy volumes by customer category is set out in the charts below. Information on the breakdown of revenues by customer category has not been published by the NRA.

Figure 58: Proportion of energy accounted by customer categories (customer categories in Standard Cubic Meters)



Customer categories are not defined in terms of typical (´residential´, ´small commercial´, etc.) groupings, but rather in terms of volume of gas consumed. Specifically, customers are grouped (and pay the relevant tariffs) depending on which of the consumption groups they fall into. The consumption groups include:

- 0 – 120 smc per year
- 121 – 480 smc per year
- 481 – 1.560 smc per year
- 1.561 – 5.000 smc per year
- 5.001 – 80.000 smc per year
- 80.001 – 200.000 smc per year
- 200.000 – 1 million smc per year
- Over 1 million smc per year

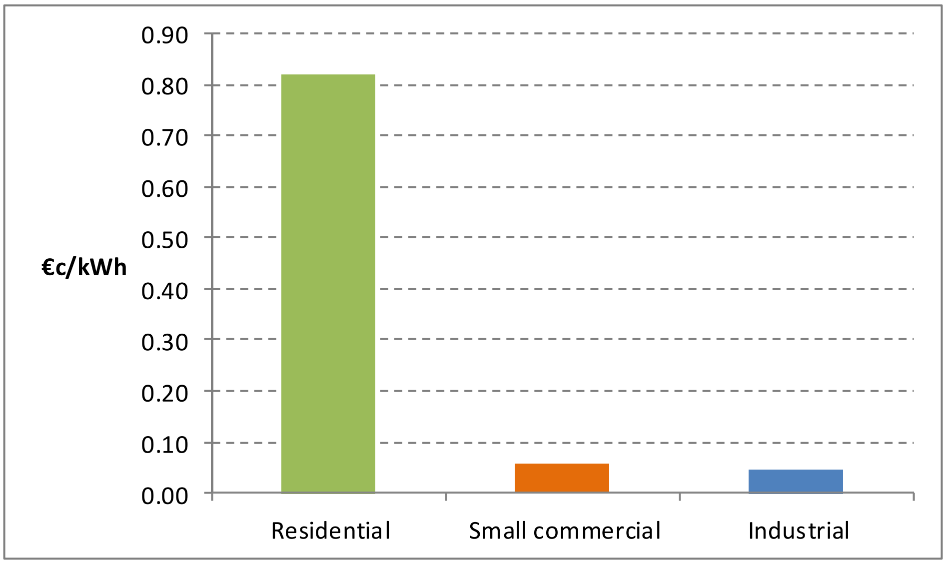
The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below:

Table 276: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Demand and reactive charges	Total
N.a.	15.000kWh	43,42	79,53		122,95
N.a.	50.000.000 kWh	43,42	27.780,16		27.823,58
N.a.	90.000.000 kWh	43,42	39.888,59		39.932,01

The resulting average tariffs per kWh are illustrated below.

Figure 59: Average charges (€cents/kWh), 2013



2. Regulation of distribution activities

A mixed regulatory regime is used in Italy wherein capital costs are subject to cost reimbursement and operating costs are subject to a price cap system.

Assets within the RAB are evaluated on the basis of a 'historical revaluated cost' approach. Every year the value of the DSOs' assets are updated by the inflation index of the price of "investment goods"

Concessions are tendered for a (maximum) period of 12 years.

2.1. General overview

The role of the NRA is to issue the methodology for tariff calculations (and to set tariffs) and to calculate allowed revenues. The Government and Parliament is involved in so much as it sets the main principles for the tariffs.

The distribution sector is regulated under a mixed regulatory regime. Capital costs are subject to cost reimbursement and operating costs are subject to a price cap system.

The distribution tariff is itemized separately to end-users. Basically, the tariff paid by consumers consists of a fixed component and a variable component. The variable component is articulated per consumption classes (that is, based on consumed volume and not based on categories such as ´residential´, ´industrial´, etc.).

Key features of the regulatory regime are set out in the following table

Table 277: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concessions at local level are tendered for a

	(maximum) period of 12 years
Duration of tariff setting regime	6 years (2014 – 2019)
Form of determination (distributor propose/regulator decide)	The Government and Parliament proposes the general principles, and the regulator calculates the tariffs to be used
Scope for appeal regulatory decision	All of the NRA´s decisions can be appealed at the Regional Administrative Court (TAR Lombardia) and, as a second stage, at the Council of State

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Operating costs are automatically updated according to a predefined rule for 6 years; hence the DSO is incentivised to reduce these costs.

At the same time the following tools are provided to mitigate risks:

- Profit sharing. It is planned that, at the end of the regulatory period 2014-2019, in setting initial values of operating costs for the next regulatory period, efficiency recovery during 2014-2019 will be shared between consumers and distributors.
- Volume risk. In Resolution 633/2013/R/gas relevant volumes for the setting of tariffs paid by consumers were considered the average volumes during the last four years, in order to reduce yearly variability of tariffs due to volume volatility. Allowed revenues in year t with reference to capital costs are based on scale variables in year t-2, while those with reference to operating costs are based on scale variables in year t.

Key components of quality of service regulation are that two premium/penalty mechanisms are implemented regarding:

- Additional yearly gas odorization degree measurements with respect to a minimum number set ex-ante by the AEEGSI;
- Reduction of the number of gas leaks reported by third parties.

Moreover, the regulation introduced obligations related to:

- Prompt intervention service;
- Included contact centre service;
- Inspection of pipes;
- Cathodic protection of steel pipes;
- Incidents and emergencies;
- Continuity of supply;
- Commercial quality.

In case commercial quality guaranteed standards are not respected, a system of automatic compensations to consumers is put into operation.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 278: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Hybrid system, partly price cap (OPEX) and partly cost of service (CAPEX)
Regulatory asset base	Assets within the RAB are evaluated on the basis of a 'historical revaluated cost' approach. Every year the value of the DSOs' assets are updated by the inflation index of the price of "investment goods"
Capital expenditure	Cost reimbursement. CAPEX are assessed every year and the corresponding tariff components are updated accordingly.
Approach to operating expenditure	Price cap. The tariff components meant to cover OPEX are updated every year following the price cap formula
Form of WACC applied	Real WACC, pre-tax
Additional revenue items (where applicable)	N.a.

The following formula is applied in determining the WACC:

$$WACC = \frac{K_E}{1-t_e} \cdot \frac{E}{D+E} + K_D \frac{D}{D+E} \cdot \frac{(1-t)}{(1-t_e)}$$

where:

- $K_E = r_f + \beta$ MRP is the cost of equity
- MRP is the Market Risk Premium
- K_D is the cost of debt
- t is the debt tax shield
- t_e is the corporate tax rate

The debt leverage is set at a target ratio considered as efficient by the regulator. The level of the allowed RoR on investments is revised every two years.

The X-component in the revenue cap or price-cap formula was calculated to allow the recovery, by 2020, of efficiency gains already achieved in year 2011. In particular, the x component for large enterprises was fixed so as to determine an operating cost in 2020 equal to 2011 average costs for the same typology of enterprises (updated to 2020), determined on the basis of their accounts.

The x-component for medium enterprises was fixed so as to determine an operating cost in 2020 equal to the weighted average of the 2011 costs for large and medium enterprises. The x-component for small enterprises was fixed equal to that of medium enterprises.

There is no direct formal interaction between the quality of service regulation and the tariff system. However, allowed revenues are *de facto* increased (decreased) if the DSO performs better (worse) than some predefined quality targets. Of course the costs of automatic compensations to consumers are not included in the allowed returns of the DSOs. Deficits deriving from the premium/penalty mechanisms are financed with tariffs paid by final consumers.

Concessions are tendered for a (maximum) period of 12 years. In the case of renewal, the DSO that loses the concession is remunerated on the basis of its concession terms.

New concessions are, on the basis of decree 12 November 2011, n. 226, at a more aggregate level, and are planned to be tendered with reference to a period of 12 years. At the end of the first concession period, non-depreciated assets are remunerated on the basis of their replacement cost.

3. Tariffs for distribution services

In addition to the fixed and variable components of the tariff paid by customers, the end-user tariff includes other aspects which are designed to support: energy efficiency interventions; RES development; quality of service; the social tariff system; district heating promotion; and the last supply service.

3.1. Distribution tariffs

50% of capital costs are allocated to the fixed component of the distribution tariffs (and are expressed in €/customer). Operating costs and the other 50% of capital costs are allocated to the variable component of the tariff (and are expressed in €/m3). The variable component is articulated per consumption classes: there is no distinction between residential, industrial and other consumers.

As regards metering, capital costs and operating costs are allocated to the (unique) fixed component of the tariff (expressed in euro/customer).

From 2015 onwards, fixed components of the tariffs will be split in three categories, depending on the meter class.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 279: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	No explicit component for distribution losses within the tariffs

Presence of uniform tariffs	No, tariffs are differentiated between six tariff zones. The variable component of the tariff in each zone is defined on the basis of a reference tariff structure per consumption classes and considering costs incurred in each zone, compared to costs in other zones.
Presence of non-linear tariffs	Yes, the variable component of the tariff is linked to the different consumption classes
Presence of regulated retail tariffs	Retailers are obliged to offer to their client the possibility to choose a regulated tariff. This option is offered only to residential customer with an annual consumption less than 200.000 m3.
Presence of social tariffs	A social tariff system is in place (bonus gas), warranting a tariff discount (therefore operating as a subsidy) or a direct payment to consumers with a household income inferior to a fixed threshold, depending on the number of components. The value of the bonus depends on the category of use of the gas, the climatic zone and the number of component of the household.

Tariffs are published as an annex of the regulator´s Resolutions and are publicly-available on the organisation´s internet website.

In addition to the fixed and variable components of the tariff paid by customers, the tariff consists of other components aimed at financing:

- Energy efficiency interventions,
- RES development,
- Quality of services,
- The social tariff system,
- District heating promotion, and
- The last supply service.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 280: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Overall, charges are of a shallow nature
	Methodology adopted	Connection charges are not regulated at the moment. The regulator has initiated a process to determine connection charges. One consultation paper was issued in 2013 concerning the principles

		and first proposals on the topic. In general, for small residential installations located not far from the existing network (typically within 10 meters) a uniform one-off connection fee applies. In other cases, connection charges basically depend on the actual costs of the connection.
Hosting capacity	Scope to refuse connection	DSOs have an obligation to connect customers requiring the connection, if capacity exists and the necessary works for the connection of the customer are technically and economically feasible
	Requirements to publish hosting capacity	No.
	Targets and/or incentive schemes to enhance hosting capacity	N.a.

The DSOs are not required to notify the regulator of the technical capacity of their networks.

4. Distribution system development and operation

DSOs are not required to develop or publish planning documents as local government is responsible for taking decisions on the network development. However, in the process of tendering for new concessions, the participants are required to propose network development plans.

In 2012 there were about 22.000.000 meters installed in Italy. Nearly 1.400 electronic meters were installed in the same year, of which almost 90% belonged to class G16 and over. Traditional meters with the so-called ´add on´ (volume converter with a data transmission system) were nearly 118.000.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 281: Approach to distribution planning

Issue	Approach
Form of distribution planning document	There is no planning document which is to be developed and submitted to the regulator. Decisions related to network development are governed by the local authorities, whom are responsible for the granting of distribution concessions.
- Key responsibilities for its development	In the tenders for the new concessions, participants have to propose network development plans. The contents of the network development plans

	proposed (included aspects related to quality of service, technological innovation) is relevant for the tender.
- Relationship with environmental policies	Indirect relationship; tenders for new concessions, which require network development plans to be drafted, require attention to be given to relevant environmental policies
- Relationship with quality of service targets	There is an indirect relationship. In the tenders for the new concessions, participants have to propose network development plans. The contents of the network development plans proposed (included aspects related to quality of service, technological innovation) is relevant for the tender.
- How trade-offs between network development and alternative technologies are treated	No explicit trade-off
- Requirements to integrate cost benefit analysis	Parties which submit a tender must also submit to local authorities the results of the cost-benefit analyses supporting some of the investment decisions included in the proposed network development plan.

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 282: Key approach to metering

Issue	Approach adopted
Discos role in metering	Responsible for: meter installation and maintenance; collection, validation and registration of data. It also normally owns the meter. One point to note is that the DSO is not responsible for collecting or managing data from meters at the point of delivery from the TSO (that is the TSO´s role).
Monopoly services in the metering	Yes, at present DSOs are the only suppliers of metering services
Smart metering functionality	Hourly measurement (excluded mass market meters); Remote reading Remote disconnection Local port to send real time consumption information to a local screens or computers (upon request of the customer).

In 2012 there were about 22.000.000 meters installed in Italy. In the same year, nearly 1.400 electronic meters were installed in the same year, of which almost 90% belonged to class G16 and over. There were nearly 118.000 traditional meters with the so-called ´add on´ (volume converter with a data transmission system) in use.

Resolution 631/2013/R/gas established plans to deploy smart meters for gas in Italy, under the following timetable:

- G40 unit customers: 100% by 31 December. 2014;
- G16 and G25 unit class customers: 60% by 31 December 2014 and 100% by 31 December 2015;
- G10 unit class customers: 15% by 31 December 2014 and 30% by 31 December 2015
- Small customers (G6 units or lower): for distributors with more than 200,000 delivery points (as at 31 December 2013): 3% by 31 December 2014;3% by 31 December 2015; 60% by 31 December 2018.[95]

It should be understood that Resolution 631/2013/R/gas introduced a mechanism to reduce the variability of the volumes considered for the calculation of mandatory tariffs paid by end consumers; and that this provision has no effect on the tariff reference recognised to distribution companies.

[95] Italian Regulatory Authority for Electricity and Gas. Annual report to ACER. 31 July 2013. Received from: http://www.autorita.energia.it/allegati/relaz_ann/13/C13_NR_Italy-EN.pdf

Country Report – Lithuania (electricity distribution)

1. Overview of the distribution sector

Almost all power distribution in Lithuania is operated by a single company, which is state-owned (unlike suppliers) and subject to regulation.

1.1. Institutional structure and responsibilities

In *Lithuania* a single, state-owned company operates distribution, supplying 1,62 million customers and covering the whole country; with the exception of 5 small local DSO that cover less than 1% of customers' demand.

Table 283: DSO characteristics

Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
6	-	1	5	Yes, for RES	N.A.
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**					

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 284: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Calculates the AR	Proposes after consultation	Provides data
Government	Issues principles in the primary law	Issues principles in the primary law	Issues principles in the primary law
NRA	Issues a methodology, approves proposal	Issues a methodology, approves proposal	Issues a methodology, calculates

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulator publishes the tariff structure one month before the official approval, and after consultations, if any, holds a public hearing. Tariffs are valid one month after approval.

1.3 Key figures on revenue and tariffs

Distribution revenues in 2013 were 450,69 million LTL (130,53 million EUR, when 1 EUR=3.4528 LTL). MV revenue was 34,6 million EUR (26%), LV revenue – 96 million EUR (74%).

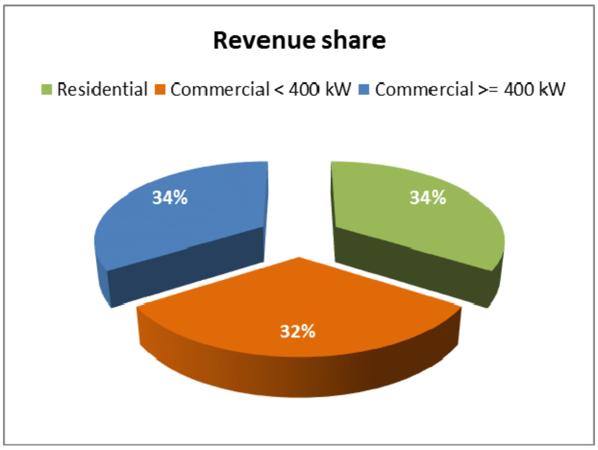
A breakdown of the number of customers, energy delivered and the revenue by customer category, including information on available tariff components for all 3 options (I, II and III tariff plans by different load factors for commercial customers), is set out in the table below.

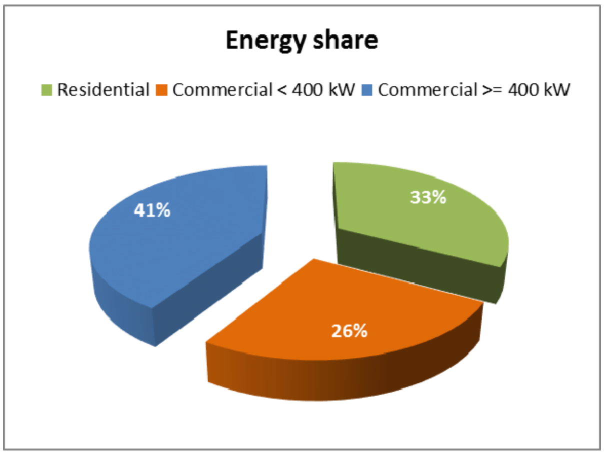
Table 285: Tariff components, customers and revenues per customer class

<table>
<tr><th>Group</th><th>Customer classes</th><th>Tariff components</th><th>Number of customers</th><th>Delivered energy (TWh)</th><th>Revenue (million EUR)</th></tr>
<tr><td>III</td><td>Commercial > 400KW</td><td>kWh & kW</td><td rowspan="3">123752</td><td>3,30</td><td>44,38</td></tr>
<tr><td>III</td><td>Commercial 30-400 KW</td><td>kWh & kW</td><td rowspan="2">2,10</td><td rowspan="2">41,77</td></tr>
<tr><td>II</td><td>Commercial <= 30KW</td><td>kWh & kW</td></tr>
<tr><td>I</td><td>Households</td><td>kWh & fixed</td><td>31503</td><td rowspan="2">2,64</td><td rowspan="2">44,38</td></tr>
<tr><td>I</td><td>Households</td><td>kWh only</td><td>1464275</td></tr>
<tr><td></td><td>Total</td><td></td><td>1619530</td><td>8,04</td><td>130,53</td></tr>
</table>

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 60: Proportion of energy and revenue accounted by customer categories





The split seems to favour households, which pay on average less than small commercial users, although their costs are probably higher (See also Figure 2 below).

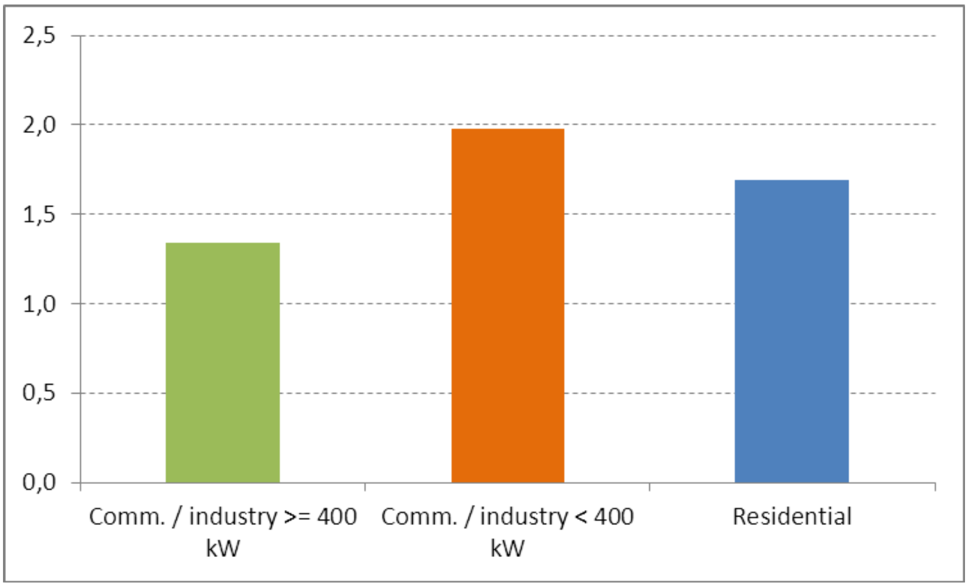
The official consumer categories are:

- Group I clients: households – physical persons, purchasing electricity for own, family or home, not related with business or profession needs (individual houses, buildings in the house territory, apartments, summerhouses, garden's plot, garages, for personal needs and vehicles, and other living objects, not used for business or profession needs);
- Group II clients: clients (except Group I clients) with their facility capacity allowance of 30 kW or less;
- Group III clients: (except Group I clients) with capacity allowance of more than 30 kW.

The breakdown of network charges by typical customer types and by component is not available.

The average tariffs per kWh for the standard typical customers in 2013 are illustrated below.

Figure 61: Average network charges (€c/kWh), 2013



2. Regulation of distribution activities

2.1. General overview

Key features of the regulatory regime are set out in the following table.

Table 286: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	License
Duration of tariff setting regime	5 years
Form of determination (distributor propose/regulator decide)	DSO proposes allowed revenue and tariff structure, NRA approves
Scope for appeal regulatory decision	N.A.

2.2. Main incentive properties of the distribution regulatory model

Lithuania adopts a 50/50 Price/Revenue-cap model, integrated by several provisions that mitigate the risk of losses or supra-normal profits for DSOs. The allowed revenue is set for five years, but is modified every year by:

a) efficiency and CPI values;
b) volume change index;
c) contingency index;
d) under/over-revenue recovery;
e) quality of services;
f) profit-sharing mechanism

In general, there is a balance between incentives and risk mitigation. In particular:

- The profit sharing mechanisms transfers to tariff reduction 50% of productivity increases between 2 and 6%, and 100% of those achieved beyond 6%.
- The DSOs bear 50% of the volume risk through volume adjustment factor.
- The correction factor evaluates the revenue over/under recovery due to data changes.
- The contingency factor reflects the impact of external changes, i.e. taxes, and of major events affecting the activity of the DSOs.
- X factor applies to OPEX only.
- Capital costs are assessed every year.
- Larger investments (over 5 million LTL or about 1.5 million EUR) are approved separately.
- Both the technical requirements and the forecast investment submitted by each DSO costs are assessed by the regulator using a simple benchmark model.
- Investment size is valued from the perspective of utilities' technical, financial and managerial capacity.
- Investment plan is assessed by the indices set in the plan (separately from other utility's activity).

In the next regulatory period, the introduction on an LRAIC model should entail the inclusion of more output based regulation, with components related to energy, capacity, and service quality.

The reliability of the electricity transportation by the distribution network is assessed by SAIDI and SAIFI indicators. The minimum reliability levels of the electricity transportation are set to the distribution network operator.

Measures (sanctions, penalties) could be applied, if the following indicators of the quality of service have worsened:

- % of the timely connected new customers;
- The restoration of the interrupted electricity supply in accordance with the set deadlines;
- % of the timely analysed claims of the customers and network users.

The price ceilings of the service is decreased/increased by 0.05 or 0.1 percent, if actual annual indices increased/decreased accordingly 5-10% or >10%, as compared to the set minimum quality level by the regulator for the 5-year regulatory period.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 287: Approach to key cost of service parameters

Parameter	Approach
Form of price control	50/50 Revenue / Price cap
Regulatory asset base	Value at historical costs.
Capital expenditure	Assessed every year, subject to benchmarking and special analysis
Approach to operating expenditure	Actual and price cap, international benchmarking may be considered
Form of capital remuneration applied	Real WACC; E/D+E set at 30%
Additional revenue items (where applicable)	Not applicable

The following formula applies for WACC calculation:

$$WACC = \frac{K_E}{1-t_e} \cdot \frac{E}{D+E} + K_D \frac{D}{D+E}$$

Where:

- ✓ $K_E = r_f + \beta$ MRP is the cost of equity
- ✓ MRP is the Market Risk Premium
- ✓ K_D is the cost of debt
- ✓ t_e is the corporate tax rate.

The WACC is updated once a regulatory period.

3. Tariffs for distribution services

The two-part (kWh+kW) tariff structure includes one, two or four time zones and is based on energy(kWh) only for households, and on peak (maximum allowed capacity) and energy for metered loads. There are 3 tariff groups, one for households and two for business usage.

3.1. Distribution tariffs

Network tariffs include both transmission and distribution, as well as a fee for public service obligations. Here is an outline of the tariffs by group (see section 1.2 above for description of the consumer groups).

Households (Group I):

- One-part tariff (energy component with one and two time zones);
- Options by consumption factor of two-part tariff: fixed and energy component with one and two time zones).

Commercial customers <30kW (Group II) in MV and LV:

- 3 options by load factor of two-part tariff: demand and energy component with one and two time zones);
- Reliability (per kW) component by 2 categories.

Commercial customers >30kW (Group III) in MV and LV (<400kW and >=400kW):

- 3 options by load factor of two-part tariff: load and energy component with one and four time zones);
- Reliability (per kW) component by 2 categories.

For the calculation of the tariff components, 2 main categories of costs are identified: MV costs and LV costs. The first cost category is recovered through the per kWh and kW tariff components equal for LV and MV consumers; the second cost component is recovered through the per kWh and kW tariff components paid by the LV consumers only, except the part of LV consumers (households), which may pay per kWh only.

Tariffs are published (Lithuanian only) at:

http://old.regula.lt/lt/elektra/tarifai/visuomeniniai_tarifai_lesto_nuo_2013%20m_sausio_1d/visuomeniniai_tarifai_lesto_nuo_2013m_sausio%20_1d/

Various other aspects of distribution tariff setting are summarized in the table below.

Table 288: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included in distribution tariffs
Presence of uniform tariffs	Each DSO has separate tariffs but main one has over 99% of customers
Presence of non-linear tariffs	No
Presence of regulated retail tariffs	For households and incumbent only
Presence of social tariffs	No

The Public Service Obligation (PSO) price reflects the support of renewable generation, effective CHPP, power system safety (reserves), nuclear decommissioning, and strategic projects mainly.

Embedded generators do not pay any distribution tariffs (or G=0).

3.2. Connection and capacity issues

Key issues in the setting of connection charges are set out in the table below.

Table 289: Summary of key issues relating to connection charges

	Issue	Approach
Determination of	Type of charges (shallow/deep)	(Mostly) Deep

charges		
	Methodology adopted	Tender or regulated cost
Hosting capacity	Scope to refuse connection	Unreasonable request
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	Yes, for each area. Reasonable connection requests must be accepted anyway.

There are two ways to determine connection charges:

1. Public procurement. This method is applied if increased permissible capacity exceeds 500 kW. In that case household consumers pay 20 %, other consumers (except household) – 40 %, producers of electricity – 100 % of contractor's working price. Also, for project preparation household consumers get 20 %, other consumers – 10 % discount.

2. Formula and Commission approved fees. This method is applied if total connected permissible capacity does not exceed 500 kW. Formula:

- Price = Fee for 1 kW * Increased permissible capacity + Fee for 1 m * Shortest geometrical distance from connection point to consumer object.

The basis for cost calculation is "semi-deep" charges for consumers and generators: the costs of new infrastructures at the same voltage level and the costs of the reinforcement of networks at the voltage level immediately above, but taking into account the rebates mentioned above.

The regulator approves connection fees based on DSO's connection cost report of last years. There are households, non-household and 100%-paid customer groups. They are divided into 4 subgroups according to the connection capacity.

4. Distribution system development and operation

Decisions are taken by DSOs, which have an obligation to supply all customers

4.1. Distribution system development

DSO all voltages network development plan is submitted at the beginning of the regulatory period of 5 years and more.

The key features of distribution system planning are summarized below.

Table 290: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Development plan to NRA on all levels at start of 5-

	year regulatory period
Key responsibilities for its development	DSO
Degree of integration with renewables plan	RES targets set by Government are explicitly taken as an input in the distribution development plan, which must create consistent hosting capacity.
Relationship with consumption trends	Demand trend must be taken into account
Relationship with quality of service targets	No explicit connection
How trade-offs between network development and alternative technologies are treated	Options for TSO / DSO explicitly discussed in network development plan.
Requirements to integrate cost benefit analysis	Yes. Used for smart grid development in 2012 but results mostly negative.

In 2012, performed smart grid cost-benefit analysis showed not so favourable results, but combining with other energy sectors, the outcome may be positive. The pilot project is under preparation and foreseen implementation in 2015.

No other DSO investments CBA is used.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 291: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	Dispatching priority for RES. Any other dispatching by TSO
Possibility to dispatch flexible loads	No
Other sources of flexibility open to DSO	No

DSOs must comply with TSO directives. Dispatching of generators and loads by TSO only.

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 292: Key approach to metering

Issue	Approach adopted
Discos role in metering	Full responsibility
Monopoly services in the metering	Yes
Smart metering functionality	a) One hour measurement b) remote reading

	c) remote detection of emergency situation and faster elimination of it d) foster the effective usage of electricity by households: real time consumption information to a local screens or computers

More than 20,000 commercial customers have smart meters. In 2015 the pilot project should be launched for 3,000 households. The results will be examined and plans approved.

Country Report – Luxembourg (electricity distribution)

1. Overview of to the distribution sector

The electricity distribution sector in Luxembourg is rather concentrated with CREOS managing more than 90% of the total distribution grid. The regulation regime in place involves a “revenue cap” with some components subject to cost reimbursement.

1.1. Institutional structure and responsibilities

In *Luxembourg* there are 5 distributor companies supplying electricity to 281428 customers with an overall circuit length of 8477 km

Summary data on industry structure is set out below.

Table 293: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	5	0	1	4	Yes	10%
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

The responsibility for setting distribution tariffs is spread between the following jurisdictions:

- The DSO;
- The NRA (*Institut Luxembourgeois de Régulation)*, an independent actor whose duties include overseeing and ensuring the full functioning of the energy market, as well as a basic universal service in the interest of consumers. The Institute ensures effective and sustainable competition by avoiding discrimination in access for new entrants.
- Government (Ministry of the Economy and Foreign Trade).

The breakdown of responsibilities as related to tariff setting is summarized in the table below.

Table 294: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges	Regulated services
DSO	Calculates for NRA approval			NA
Government	Defines main principles			NA
NRA	Set rules, approves	X	X	NA

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adopted to setting distribution tariffs involves the following steps:

- the Ministry of the Economy issues principles in the primary law (*Loi du 1er août 2007 relative à l'organisation du marché de l'électricité* modified by *Loi du 18 décembre 2009*, *Loi du 17 décembre 2010*, *Loi du 7 août 2012*);
- the *Institut Luxembourgeois de Régulation* regulator issues consultation papers and holds public hearings in order to adopt a methodology for the determination of the distribution tariffs[96];
- the *Institut Luxembourgeois de Régulation* issued a methodology through *Règlement E12/05/ILR du 22 mars 2012 fixant les méthodes de détermination des tarifs d'utilisation des réseaux de transport, de distribution et industriels et des services accessoires à l'utilisation des réseaux pour la période de régulation 2013 à 2016 et abrogeant le règlement E09/03/ILR du 2 février 2009*;
- the DSO calculates the allowed revenue;
- the *Institut Luxembourgeois de Régulation* approves it.

1.2. Key figures on revenue and tariffs

Distribution revenues in 2013 were € 162.25 million. No further split by service type is available.

A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below[97].

[96]http://www.ilr.public.lu/electricite/consultations/conspub301111/index.html;http://www.ilr.public.lu/electricite/consultations/conspub050711/index.html

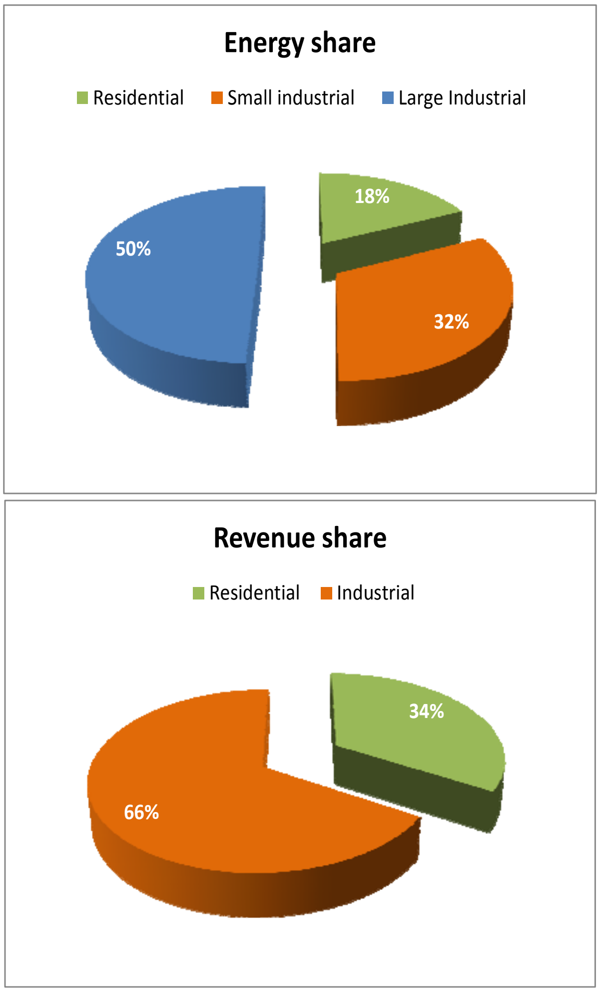
[97] In Luxembourg there isn't a definition of typical consumer, which is normally used to allow tariff comparisons. When such comparisons are done, than customer profiles of Eurostat are used.

Table 295: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenue[98]
Household	KWh, fixed charge[99]	224084	54490506
Small industrial	KWh, KW	57140	107759494
Large industrial	KWh, KW	204	
Total	-	281428	

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 62: Proportion of energy and revenue accounted by customer categories[100]



[98] Estimated.
[99] 2€/month
[100] Average annual network cost is available only for residential customers. Revenue shares are estimated by REF-E according to available data.

These show a larger share of costs borne by residential category of consumers, which may be in line with costs.

Customer categories are defined as follows[101]:

- Non metered Low Voltage Synthetic Load Profile (LV SLP)
- Low voltage final customer (LV)
- Final customers 20 kV
- Final customers 65 kV
- Final customers 220 kV

The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below[102]:

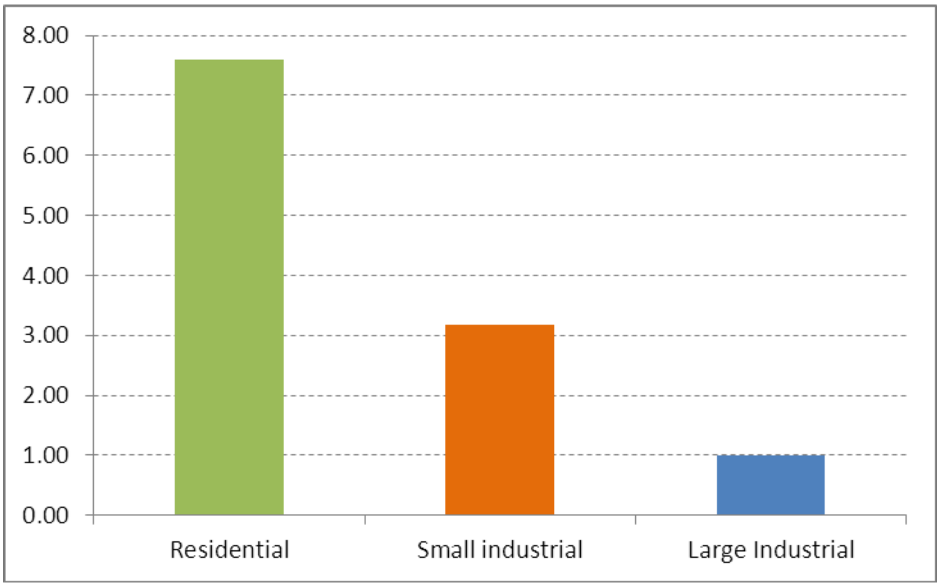
Table 296: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Load and reactive charges	Meter	Total
Residential (LV)[103]	3500kWh	24	210,7	-	30,96	265,66
Small industrial[104]	50MWh	-	250	200	1136,76	1586,86
Industrial[105]	24000MWh	-	52800	183450	1632,72	237883

The resulting average tariffs per kWh are illustrated below.

[101] Those categories refer to CREOS which manages more than 90% of the distribution grid in Luxembourg.
[102] REF-E estimates on Creos tariffs as approved for the year 2013 by the NRA.
[103] REF-E Hyphotesis: LV not metered final customer.
[104] REF-E Hyphothesis: final customers 65 kV, 10 kW demand, > 3000 h/year time of use.
[105] REF-E Hyphothesis: final customers 220 kV, 5000 kW, 7000 h/year time of use.

Figure 63: Average network charges (€cent/kWh), 2014



An example of network tariffs applying in 2014, by CREOS DSO is available at the following link: http://www.creos-net.lu/fileadmin/dokumente/creos_luxembourg/Documentation/Condition_generales/Tarif_Electricite.pdf

2. Regulation of distribution activities

2.1. General overview

The role of the DSO in *Luxembourg* is to operate, develop and maintain the distribution grid, ensuring a non-discriminatory treatment to all grid users. It has a duty to give to grid users the information they need in order to access the grid, it is in charge of metering activities and it ensures the supplier access to metered data.

The Institut Luxembourgeois de Régulation's duties include overseeing and ensuring the full functioning of the energy market, as well as a basic universal service in the interest of consumers and ensure effective and sustainable competition by avoiding discrimination in access for new entrants.

The distribution sector is regulated under a concession regime. A mix of "cost-reimbursement" and "incentive-based" form of regulation is applied.

Key features of the regulatory regime are set out in the following table:

Table 297: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession (10 years). Tariffs take into account costs actually paid by the operator: the concession lease and other concession costs are

	covered as an OPEX
Duration of tariff setting regime	4 years (2013-2016)
Form of determination (distributor propose/regulator decide)	distributor propose/regulator decide
Scope for appeal regulatory decision	Not available

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Controllable OPEX are updated automatically according to a predefined rule, thus the DSO is incentivised to reduce costs.
- Investment projects that cost more than 1 million EUR are considered as planned in the RAB during the regulatory period. Thus the DSO is incentivised to realize the project with less costs than budgeted.

At the same time the following tools are provided to mitigate risks:

- Distribution tariffs are updated every year in order to mitigate the “volume risk”;
- The yearly difference between the revised maximum allowed revenue and the actual income is put on a regulatory accounting term (RAT). If the total amount of the RAT exceeds +-5% of the allowed revenue, the part exceeding 5% is transferred to the consumers via the tariffs for the next year of the regulatory period;
- Investments by the distribution companies are subjected to a form of soft approval. Every year the DSO publishes an investment plan. Although this plan is not formally approved or assessed by the regulator, it allows the regulators to spot issues and intervene to address them.

For tariff related quality of service regulation, at the moment not enough data has been collected. The regulation of the quality of service is set to zero for this regulatory period. This is going to change for the subsequent regulatory periods. For non-tariff related regulation there are technical standard set by the DSO and approved by the regulator.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 298: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Mixed “cost reimbursement”-“revenue cap”
Regulatory asset base	Historic or re-evaluated cost, book value
Capital expenditure	Some capital costs are subject to “cost reimbursement” and some are subject to a “revenue cap”

Approach to operating expenditure	Non-controllable operating costs are estimated and subject to "cost reimbursement" while controllable operating costs are subject to a "revenue cap" and updated automatically according to a predefined rule thus the DSO is incentivised to reduce costs.
Form of capital remuneration applied	WACC nominal pre-tax evaluated according to historic costs
Additional revenue items (where applicable)	Not available

The following formula is applied in determining the WACC:

$$WACC_{nom\ pre\text{-}tax} = g \cdot (RFR_{nom} + DP) + (1 - g) \cdot \frac{RFR_{nom} + \beta_E \cdot ERP}{1 - T} = 7{,}60\%$$

DP= Debt Premium
T= Tax rate
G= Gearing
ERP= (Equity Risk Premium)
$ß_E$= Equity Beta
RFR_{nom} =(Nominal Risk Free Rate)

To determinate the WACC formula the regulator adopts the Capital Asset Price Model (CAPM). In order to estimate the WACC parameters, the Regulator adopts a medium term approach[106] with the aim to adapt to financial market trends and to avoid volatility. The medium term approach allows to fix a remuneration tax which parameters can be updated every four years, unless the financial markets' evolution require an earlier adaptation.

No formal document is published explaining how the regulator has selected the X value.

3. Tariffs for distribution services

[106] *Pour la détermination des taux de rémunération des capitaux investis, l'Institut fait appel au modèle d'évaluation des actifs financiers (Medaf) communément utilisé en finance et dans le contexte des secteurs régulés en Europe. Pour l'estimation des paramètres du coût moyen pondéré du capital (WACC ou Weighted Average Cost of Capital), l'Institut adopte une attitude à moyen terme à visibilité suffisante, qui a pour objectif d'être proche des marches financiers tout en évitant une volatilité non souhaitée. L'optique moyen terme permet de fixer un taux de remuneration dont les paramètres pourraient être revus après une période de 4 ans à moins que l'évolution sur les marchés financiersb rende une adaptation préalable indispensable.*

Distribution tariffs are conventionally split between a per kW tariff component and a kWh tariff. Connection charges are set using standard costs proposed by DSO and approved by the regulator for small consumers. For large consumers an estimation is carried out by the DSO. DSO can refuse connection for economic and security of supply reasons.

3.1. Distribution tariffs: additional issues

The DSO is in charge of setting the distribution tariffs (based on the allowed revenue). Where possible costs are assigned directly to the concerned voltage level. Indirect costs are assigned to the different voltage levels by using a key (different for each DSO). Then, those costs are conventionally split (different for each DSO) between a per kW tariff component (where KW represents the maximum power used by the consumer during the year) and a kWh tariff. All, except LV SLP customers are charged a distribution tariff including:

- a per kW based on actual peak demand over the year
- a per kWh charge on the actual consumption

These tariffs differ according to the time of use (< 3000 h/year, > 3000 h/year).

LV clients with a SLP only pay 2€ per month and a per kWh charge on the actual consumption.

For residential customers, the supply has to be offered and billed as integrated retail tariff.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 299: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	The distribution tariffs include the cost of losses
Presence of uniform tariffs	Each DSO charges different tariffs but within each DSO network they are the same
Presence of non-linear tariffs	All tariff components are linear, except a 2 EUR flat monthly charge for LV SLP
Presence of regulated retail tariffs	No
Presence of social tariffs	No
Presence of other components	The tariffs charged by DSOs includes financing of the NRA and, in the future, charging stations for electric vehicles
Distribution tariff for generators	Embedded generators do not pay any distribution tariffs

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 300: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Shallow charges for small customers, deep(er) charges for larger customers.
	Methodology adopted	Standard costs are proposed by the DSOs and approved by the regulator for small consumers; for larger consumers the DSO makes an estimate based on its cost
Hosting capacity	Scope to refuse connection	The DSO can refuse connection only if that would entail an unreasonable cost or may be dangerous for the security of supply. In case of refusal of connection, the regulator is notified and can be asked by the party seeking connection to revert the DSO's decision
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	No

4. Distribution system development and operation

System development is decided by the DSO and the NRA is only kept informed. The DSO can require large embedded generators to disconnect in case of grid congestion and can directly control flexible loads. Deployment of smart meters will start soon.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 301: Approach to distribution planning

Issue	Approach
Form of distribution planning document	
- Key responsibilities for its development	The distribution system development plan is made by DSOs and notified to the Regulator but not approved nor published
- Degree of integration with renewables plan	The distribution network development plans are not (at least explicitly) connected with the renewable generation targets.
- Relationship with consumption trends	The evolution of consumption in the distribution area is explicitly considered in the development plan based on a detailed spatial demand forecast
- Relationship with quality of service	The plan does not explicitly illustrate the relationship

targets	between each (type of) investment and the benefits in terms of increased quality of services
- How trade-offs between network development and alternative technologies are treated	The network development plan reports only the decisions of the DSOs. The analysis on which those decisions are based are not public.
- Requirements to integrate cost benefit analysis	The network development plan reports only the decisions of the DSOs. The analysis on which those decisions are based are not public.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 302: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	DSOs can only require larger embedded units to disconnect in case the distribution system cannot host their injections
Possibility to dispatch flexible loads	The DSOs can directly control flexible loads through remotely operated switches
Other sources of flexibility open to DSO	None

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 303: Key approach to metering

Issue	Approach adopted
DSOs role in metering	DSOS have full responsibilities for metering and own the meters
Monopoly services in the metering	DSOS are monopolists in metering activities
Smart metering functionality	a) quarter-of an hour measurement b) remote reading c) remote disconnection/reconnection of customers d) remote control of the maximum power that can be withdrawn e) remote operation of appliances at the consumer's premises f) local port to send real time consumption information to a local screens or computers

At the moment no smart meters are installed. The DSOs however have to start soon with the deployment and have to prove to the Regulator that by 31st December 2018 95% of their clients have a smart meter. A breakdown by customer category is illustrated below.

The following preliminary information on the impact of smart meter roll out is available[107]

Table 304: Effects from the smart meters deployment.

DSO	Total number of households	Number of households with a SM	Electricity consumption reduction	Euro saved per year for an average household
	224,084	0	1%-5% peak consumption (theoretical)	26.5-39.9 (theoretical)

[107] Schwartz & Co. Etude économique à long terme pour la mise en place de compteurs intelligents dans les réseaux électriques et gaziers au Luxembourg, préparé pour le Ministère de l'Économie et du Commerce Extérieur du Luxembourg, 2011.

Country Report - Luxembourg (Gas)

1. Overview of to the distribution sector

The gas distribution network is less concentrated than the electricity one, with CREOS supplying around 50% of total customers connected to the gas grid. The regulation regime in place involves a "revenue cap" with some components subject to cost reimbursement.

1.1. Institutional structure and responsibilities

In *Luxembourg* there are 3 distributors supplying gas to 84277 customers through a 1214 km^2 gas distribution grid. Summary data on industry structure is set out below.

Table 305: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	3	0	1 (Creos)[108]	3	Yes	100 %
***exemption from legal unbundling: DSO with less than 100,000 customers are subjected to accounting unbundling**						

The responsibility for setting distribution tariffs is spread between the following jurisdictions (for example):

- The DSO;
- The NRA (*Institut Luxembourgeois de Régulation*, it's an independent actor whose duties include overseeing and ensuring the full functioning of the energy market, as well as a basic universal service in the interest of consumers. Ensuring effective and sustainable competition by avoiding discrimination in access for new entrants, the Institute allows consumers to freely choose between a growing number of offers and products at fair and competitive prices);
- Government (Ministry of the Economy and Foreign Trade).

[108] Rapport de l'Institut Luxembourgeois de Régulation sur ses activités et sur l'exécution de ses missions dans les secteurs de l'électricité et du gaz naturel, année 2012. Creos is also the main electricity DSO. It has more than 100000 customers in the electricity distribution sector, therefore it is subject to unbundling provisions.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 306: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges	Regulated services
DSO	Calculates for NRA approval			NA
Government	Defines main principles			NA
NRA	Set rules, approves	X	X	NA

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adopted to setting distribution tariffs involves the following steps:

- the Ministry of the Economy and Foreign Trade issued principles in the primary law (*Loi du 1er août 2007 relative à l'organisation du marché du gaz naturel* modified by *Loi du 18 décembre 2009* and by *Loi du 7 août 2012*);
- the *Institut Luxembourgeois de Régulation* regulator issued two consultation papers and held public hearings in order to adopt a methodology for the determination of the distribution tariffs[109];
- the *Institut Luxembourgeois de Régulation* issued a methodology through *Règlement E12/06/ILR du 22 mars 2012 fixant les méthodes de détermination des tarifs d'utilisation des réseaux de transport, de distribution et industriels et des services accessoires à l'utilisation des réseaux pour la période de régulation 2013 à 2016 et abrogeant le règlement E09/04/ILR du 2 février 2009*;
- the DSO calculates the allowed revenue;
- the *Institut Luxembourgeois de Régulation* approves it.

1.2. Key figures on revenue and tariffs

Distribution revenues in 2013 were € 33,46 million. No further split by service type is available.

A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 307: Tariff components, customers and revenues per customer class

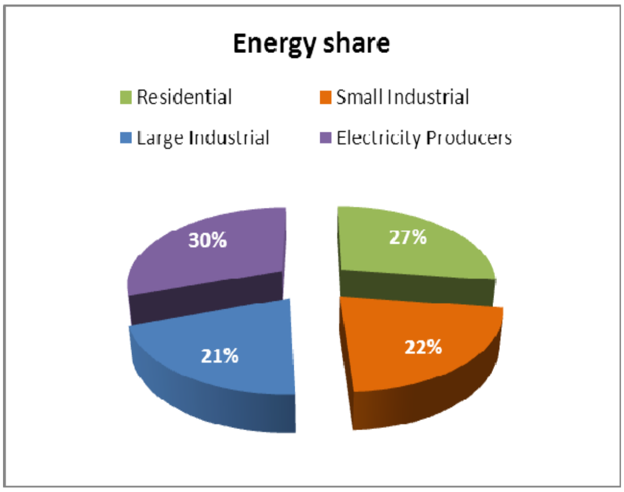
Customer classes	Tariff components	Number of customers	Revenue
Household	Nm^3, KW	79157	NA

[109]http://www.ilr.public.lu/electricite/consultations/conspub301111/index.html;http://www.ilr.public.lu/electricite/consultations/conspub050711/index.html

Small industrial	Nm^3, KW	5024	NA
Large Industrial	Nm^3, KW	5	NA
Electricity producers	Nm^3, KW	91	NA
Total	-	84277	

The breakdown of energy volumes by customer category are set out in the charts below.

Figure 64: Proportion of energy by customer categories



All consumers are charged a distribution tariff including two components:

- a capacity related charge, based on the contractual or actual maximum yearly withdrawal
- an energy related component.

There are no classes of consumers.

The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below[110]:

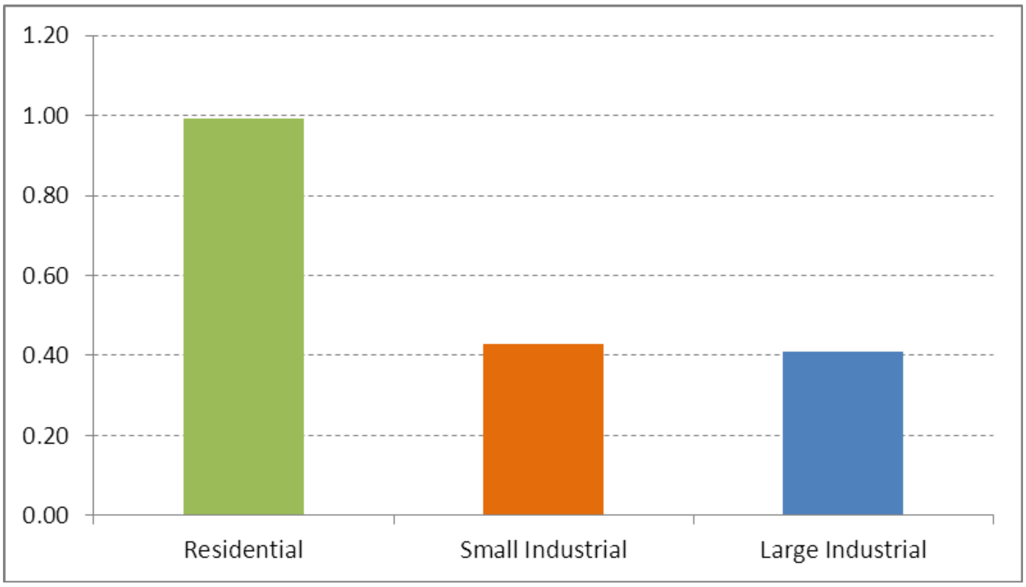
Table 308: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Meter	Total
Residential	15000 kWh	-	111,36	37,56	148,9
Small industrial	50000 MWh	38992,6	173253,6	1554	213799,2
Industrial	90000 MWh	57185,3	308217,2	2455,6	367858,1

110 REF-E estimates based on Creos tariffs for the year 2013 as approved by the NRA.

The resulting average tariffs per kWh are illustrated below[111].

Figure 65: Average network charges (€cent/kWh), 2013



An example of network tariffs applied in 2014, by CREOS DSO is available at the following link: http://www.creos-net.lu/fileadmin/dokumente/creos_luxembourg/Documentation/Condition_generales/Tarif_Gaz.pdf

2. Regulation of distribution activities

2.1. General overview

The role of the DSO in *Luxembourg* is to operate, develop and maintain the distribution grid, ensuring a non-discriminatory treatment to all grid users. It has a duty to give to grid users the information they need in order to access the grid and it is in charge of metering activities and it ensures the supplier access to metered data.

The Institut Luxembourgeois de Régulation's duties include overseeing and ensuring the full functioning of the energy market, as well as a basic universal service in the interest of consumers and ensure effective and sustainable competition by avoiding discrimination in access for new entrants.

The distribution sector is regulated under a licence regime. A mix of "cost-reimbursement" and "incentive-based" form of regulation is applied.

[111] Data from the NRA were only available for the meter sub-component. All the other components were calculated as REF-E estimates based on CREOS tariffs.

For residential customers, the supply has to be offered and billed as integrated retail tariff.

Key features of the regulatory regime are set out in the following table:

Table 309: Main features of the regulatory regime

Issue	Approach
Type of regime	Licence (Ministerial authorisation)
Duration of tariff setting regime	2013-2016
Form of determination	Distributor propose, regulator decide
Scope for appeal regulatory decision	Not available

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Controllable OPEX are updated automatically according to a predefined rule, thus the DSO is incentivised to reduce costs.
- Investment projects that cost more than 500,000 EUR are considered as planned in the RAB during the regulatory period. Thus the DSO is incentivised to realize the project with less costs than budgeted.

At the same time the following tools are provided to mitigate risks:

- Distribution tariffs are updated every year in order to mitigate the “volume risk”.
- The yearly difference between the revised maximum allowed revenue and the actual income is put on a regulatory accounting term (RAT). If the total amount of the RAT exceeds +-5% of the allowed revenue, the part exceeding 5% is transferred to the consumers via the tariffs for the next year of the regulatory period.
- Investments by the distribution companies are subjected to a form of soft approval. Every year the DSO publishes an investment plan. Although this plan is not formally approved or assessed by the regulator, it allows the regulators to spot issues and intervene to address them.

In the natural gas market, the NRA does not have the legal obligation to monitor quality and thus cannot collect any data on this subject. For non-tariff related regulation there are technical standard set by the DSO and approved by the regulator.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 310: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Mixed "cost reimbursement"-"revenue cap"
Regulatory asset base	Historic or re-evaluated cost, book value
Capital expenditure	Some capital costs are subject to "cost reimbursement" and some are subject to a "revenue cap"
Approach to operating expenditure	Non-controllable operating costs are subject to "cost reimbursement" while controllable operating costs are subject to a "revenue cap". Controllable OPEX are updated automatically according to a predefined rule thus the DSO is incentivised to reduce costs.
Form of WACC applied	WACC nominal pre-tax evaluated according to historic costs
Additional revenue items (where applicable)	Not available

The following formula is applied in determining the WACC:

$$WACC_{nom\ pre\text{-}tax} = g \cdot (RFR_{nom} + DP) + (1 - g) \cdot \frac{RFR_{nom} + ß_E \cdot ERP}{1 - T} = 7{,}60\%$$

DP= Debt Premium
T= Tax rate
G= Gearing
ERP= (Equity Risk Premium)
$ß_E$= Equity Beta
RFR_{nom} =(Nominal Risk Free Rate)

To determine the WACC formula, the regulator adopts the Capital Asset Price Model (CAPM). In order to estimate the WACC parameters the Regulator adopts a medium term approach[112] with the aim to adapt to financial market's trends and to avoid volatility. The medium term approach allows to fix a remuneration tax which parameters can be updated every four years, unless the financial markets' evolution require an earlier adaptation.

[112] *Pour la détermination des taux de rémunération des capitaux investis, l'Institut fait appel au modèle d'évaluation des actifs financiers (Medaf) communément utilisé en finance et dans le contexte des secteurs régulés en Europe. Pour l'estimation des paramètres du coût moyen pondéré du capital (WACC ou Weighted Average Cost of Capital), l'Institut adopte une attitude à moyen terme à visibilité suffisante, qui a pour objectif d'être proche des marches financiers tout en évitant une volatilité non souhaitée. L'optique moyen terme permet de fixer un taux de remuneration dont les paramètres pourraient être revus après une période de 4 ans à moins que l'évolution sur les marchés financiersb rende une adaptation préalable indispensable.*

No formal document is published explaining how the regulator has selected the X value.

3. Tariffs for distribution services

There are 3 DSOs with different tariffs and generally for each DSO there are different tariff blocks depending on the consumption volume.

The DSO is obliged to connect the customer only when the network is already in place.

3.1. Distribution tariffs: additional issues

The DSO is in charge of setting the distribution tariffs. Where possible costs are assigned directly to the concerned pressure level. Indirect costs are assigned to the different pressure levels by using a key (different for each DSO). Then, those costs are conventionally split (different for each DSO) between a capacity (kW) tariff component and an energy (m^3) tariff component.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 311: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	The cost of losses are included in the tariff
Presence of uniform tariffs	There are 3 DSOs with different tariffs
Presence of non-linear tariffs	There are different tariff blocks depending on the consumption. For one DSO (Ville de Dudelange) there are two tariffs blocks depending on the installed capacity.
Presence of other components	The tariffs charged by DSOs includes financing of the NRA.
Presence of regulated retail tariffs	No
Presence of social tariffs	No

3.2. Connection charges

For residential installations and small LP consumers a uniform one-off connection fee set by the DSO applies. For larger consumers and generators connection costs are computed case by case

Key issues in the setting of connection charges are set out in the table below.

Table 312: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Shallow charges for small consumers. Deep (er) charges for larger consumers.
	Methodology adopted	For residential installations and small LP consumers a uniform one-off connection fee set by the DSO applies. For larger consumers and generators connection costs are computed case by case.
Hosting capacity	Scope to refuse connection	The DSO is obliged to connect the customer only when the network is already in place (no universal service obligation). The DSO can refuse connection only if that would entail an unreasonable cost or may be dangerous for the security of supply. In case of refusal of connection, the regulator is notified and can be asked by the party seeking connection to revert the DSO's decision
	Requirements to publish technical capacity capacity	None

4. Distribution system development and operation

System development is decided by the DSO and the NRA is only kept informed. Deployment of smart meters will start soon.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 313: Approach to distribution planning

Issue	Approach
Form of distribution planning document	
Key responsibilities for its development	The distribution system development plan is made by DSOs and notified to the Regulator but not approved nor published
Degree of integration with environmental policies	Not available
Relationship with quality of service targets	The plan does not explicitly illustrate the relationship between each (type of) investment and the benefits in terms of increased quality of services
How trade-offs between network development and alternative technologies are treated	The network development plan reports only the decisions of the DSOs. The analysis on which those decisions are based are not public.
Requirements to integrate cost benefit analysis	The network development plan reports only the decisions of the DSOs. The analysis on which those

	decisions are based are not public.

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 314: Key approach to metering

Issue	Approach adopted
DSOs role in metering	DSO a) owns the meter b) is responsible for the collection of data from the meter c) is responsible for all other data management functions (validation, storing, sending the data to parties entitled access to them ...)
Monopoly services in the metering	DSO's are monopolists in metering activities
Smart metering functionality	a) hourly measurement b) remote reading c) remote disconnection/reconnection of customers d) remote control of the maximum power that can be withdrawn e) remote operation of appliances at the consumer's premises f) local port to send real time consumption information to a local screens or computers

At the moment no smart meters are installed. The DSOs however have to start soon with the deployment and have to prove to the regulator that by 31st December 2020 95% of their clients have a smart meter.

The following preliminary information on the impact of smart meter roll out is available[113].

Table 315: Effects from the smart meters deployment.

DSO	Total number of households	Number of households with a SM	Electricity consumption reduction	Euro saved per year for an average household
Name	79157	0	0,5%-2% (theoretical)	70,6-91,8 (theoretical)

[113] Schwartz & Co. Etude économique à long terme pour la mise en place de compteurs intelligents dans les réseaux électriques et gaziers au Luxembourg, préparé pour le Ministère de l'Économie et du Commerce Extérieur du Luxembourg, 2011.

Country Report – Malta (electricity distribution)

1. Overview of to the distribution sector

In Malta, the electricity distribution sector is completely concentrated in just one DSO, Enemalta PLC, mostly owned by the state, which is also the main producer of electricity (except for small RES) and is the only licensed supplier to final customers.

There are no transmission systems and no transmission system operators.

The sector is fully regulated: All customers of electricity are on a regulated retail tariff. In view of the fact that there is only one supplier of electricity it is not possible to implement customer switching.

The regulator, the Malta Resources Authority (MRA), approves the tariffs proposed by the DSO.

1.1. Institutional structure and responsibilities

In Malta there is just one Distributor, Enemalta PLC. They are supplying electricity to 285214 customers covering the whole country. In 2012, the total amount of electricity generated in the country was 2,291TWh, 99%, 2,268TWh, from fossil fuel coming from the two power stations owned by Enemalta PLC, and the rest produced from renewable energy sources estimated at 0,0225TWh.

Summary data on industry structure is set out below.

Table 316: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption	Share of total demand
Malta	1	Not applicable	Not applicable[114]	0	NO	100%

The responsibility for setting distribution tariffs is spread between the following jurisdictions:

[114] By virtue of Article 44-Derogations, the requirements of Article 9 (Unbundling of the transmission systems and transmission system operator) and Article 26 (Unbundling of distribution system operators) do not apply to Malta.

- **The DSO, Enemalta**, proposes the methodologies to use in the tariffs valuation and calculates tariffs
- **The Regulator, the Malta Resources Authority (MRA),** has the duty and the authority to fix or approve tariffs or methodologies used to calculate or establish the terms and conditions for connection and access to the distribution system.
  The regulator may also require the DSO to change the tariffs or methodologies used for determining the distribution tariffs to ensure that these are proportional and non-discriminatory.
- **The Ministry** issues principles in the primary law and publishes the applicable tariffs and methodologies in the Electricity Supply Regulations (S.L.423.01).

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 317: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges	Regulated services
DSO	Calculates for NRA approval	Calculates for NRA approval	Calculates for NRA approval	NA
Government	Issues principles in primary law	Consulted by Regulator	Consulted by Regulator	NA
NRA	Approves	Approves	Approves	NA

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process implemented to set distribution tariffs involves the following steps:

- The Ministry issues principles in the primary law. The DSO calculates the allowed revenue and the regulator approves it.
- The DSO proposes the tariff structure. The regulator approves it after consultation with stakeholders, including ministries

1.2. Key figures on revenue and tariffs

The Distribution revenues in 2013 separate from other revenues are not available. No further split by service type is available. Total distribution network cost was 29003000€ in 2013.

A breakdown of the total revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 318: Tariff components, customers and revenues per customer class for 2013

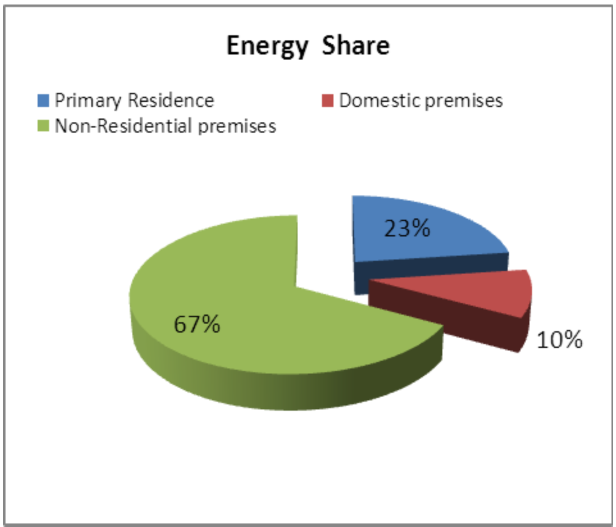
Customer classes	Tariff components	Number of customers	Revenue[115]
Primary residence	Fixed Charge + Energy charge €c/ kWh tariff structure based on consumption level + €/kW maximum demand charge for connection services rated above 60A/phase	148173	71270176,86
Domestic premises	Fixed Charge + Energy charge €/kWh tariff structure based on consumption level + €/kW maximum demand charge for connection services rated above 60A/phase	85820	43240877,29
Non-residential premises	Fixed Charge + Energy charge €/ kWh tariff structure based on consumption level + €/kW maximum demand charge for connection services rated above 60A/phase	51221	215563088,12
Total	-	**285214**	330074142,27

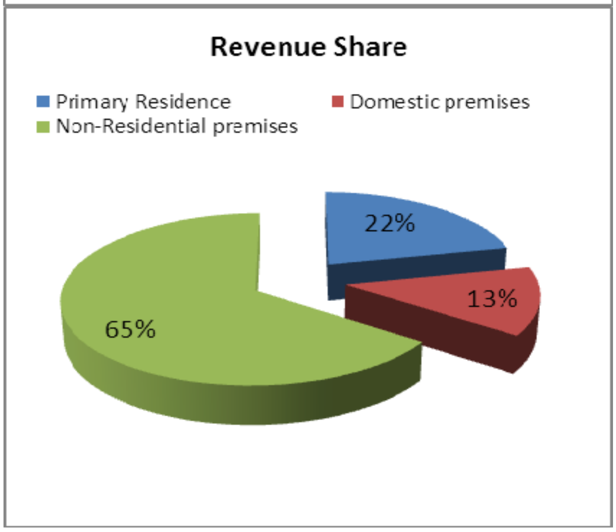
The breakdown of energy volumes and total[116] revenue by customer category are set out in the charts below.

[115] Total revenues including energy and distribution and supply charges. Total distribution network cost was 29003000 €. Split by customer class is not available.

[116] Energy and distribution and supply costs

Figure 66: Proportion of energy and revenue accounted by customer categories





Customer categories differentiate between Primary residences, Domestic and Non-residential, which are defined as follows:

- Primary Residences (Residential) – Electricity consumed in premises intended for domestic use and which are registered as a primary residence.
- Domestic - The domestic tariffs are applicable for electricity consumed in premises intended for domestic use and which are not registered as a primary residence.
- Non-Residential: The non-residential tariffs are applicable for electricity consumed in all the other premises which are not registered either as a primary residence or as domestic premises.

All consumers of electricity are on regulated retail tariffs which consist mainly of a kWh rate and a fixed annual service charge.

In addition, consumers with a service connection capacity exceeding 60Amps/phase have to pay a maximum demand tariff.

The tariff structure provides the possibility for households to benefit from a percentage eco reduction on their electricity consumption bill on one registered primary residence as follows:

- Households composed of two or more persons may benefit from a two tier eco reduction mechanism provided that the consumption per person does not exceed 1750kWh per annum. A reduction of 25% in the consumption bill is possible if the consumption does not exceed 1000kWh per person for the first tier. The second tier consists of a reduction of 15% in the bill on the next 750 kWh per person/household.
- Single person households enjoy a reduction of 25% in their consumption bill if their annual electricity consumption does not exceed the 2000kWh/annum.

The kWh tariff structure consists of a number of tiers of consumption bands with the corresponding kWh tariff.The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below:

Table 319: Breakdown of average annual network charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Network cost[117]	Total
Households	3.500 kWh	77 € (0,022€/kWh)	77 € (0,022€/kWh)
Small Industrial	50 MWh	1100 € (0,022€/kWh)	1100 € (0,022€/kWh)
Large Industrial	24000 MWh	528000 € (0,022€/kWh)	528000 € (0,022€/kWh)

Table 320: the retail tariffs118 applied in 2013 to final customers in Malta

Customer Type	Fixed Charges Service charge/annum	Energy Charges Bands	Cumulative consumption (kWh)	Consumption Tariff Incl. 5% VAT[119] (€)	Maximum Demand (connection capacity > 60Amps/phase)
Primary Residence	Single Phase (SP) - € 65,00 Triple Phase (3P) - € 195,00	Band 1	0-2000	0,161	MD- €21,05/kW/annum for service capacity >60A/phase
		Band 2	2001-6000	0,173	
		Band 3	6001-10000	0,189	
		Band 4	10001-20000	0,36	
		Band 5	>20000	0,62	

[117] This is an overall average per kWh of all network cost charges-fixed and €/kWh components
[118] The retail tariffs cover the generation, distribution and supply costs
[119] Tariffs for primary residence and domestic premises include 5% VAT. Non-residential tariffs are exclusive of VAT.

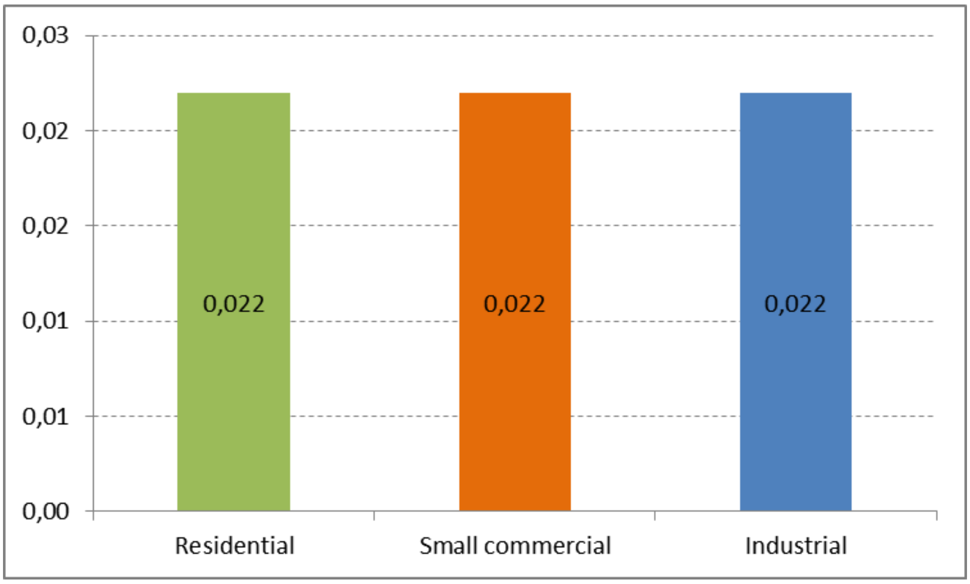
Domestic premises	SP - €65,00 3P - €195,00	Band 1	0-2000	0,21	MD-€21,05/kW/annum for service capacity >60A/phase
		Band 2	2001-6000	0,223	
		Band 3	6001-10000	0,238	
		Band 4	10001-20000	0,44	
		Band 5	>20000	0,7	
Non-Residential (kWh)[120]	SP - € 120,00 3P - € 360,00	Band 1	0-2000	0,162	MD - €20,50/kW/annum consumption > 5000 MWh /year – MD charge-€17,20/kW/annum
		Band 2	2001-6000	0,170	
		Band 3	6001-10000	0,183	
		Band 4	10001-20000	0,198	
		Band 5	20001-60000	0,215	
		Band 6	600001-100000	0,200	
		Band 7	1000001-1000000	0,187	
		Band 8	1000001-5000000	0,170	
		Band 9	>5000000	0,144	
Non-Residential (kVAh)[121]	SP - € 120,00 3P - € 360,00	Band 1	0-2000	0,149	MD - €19,20/kVA/annum consumption > 5500 MVAh /year: MD-€17,20/kVA/annum
		Band 2	2001-6000	0,156	
		Band 3	6001-10000	0,168	
		Band 4	10001-20000	0,182	
		Band 5	20001-60000	0,198	
		Band 6	600001-100000	0,184	
		Band 7	1000001-1000000	0,172	
		Band 8	1000001-5000000	0,156	
		Band 9	>5000000	0,132	

The resulting average tariffs per kWh are illustrated below.

[120] Non-residential consumers with consumption exceeding 5GWh may choose to be billed on a night and day tariff.

[121] Non-residential consumers with consumption exceeding 5,5GVAh may choose to be billed on a night and day tariff.

Figure 67: Average network charges (€/kWh), 2013



2. Regulation of distribution activities

The distribution sector is regulated under a cost reimbursement regulatory model.

This model has neither incentive based-elements, nor risk mitigation methods or systems of financial compensation/penalties in terms of quality service implemented.

There is no defined tariff revision timetable. In addition no ex post assessment of “usefulness” is carried out.

The regulator focus on the cost estimates provided by the DSO based on the assumptions that the DSO will have to satisfy all the reasonable demands for service, in order to fix and approve the distribution tariffs.

2.1. General overview

Enemalta PLC [122]is a vertically integrated public liability company licensed to perform the activities of generation, distribution system operator and supply of electricity to final customers. Malta was granted derogation from the requirements of Article 26 of Directive 2009/72EC (unbundling of distribution system operators), and unbundling is required at management accounts level only.

As the DSO, Enemalta PLC has the following tasks and responsibilities assigned by law:

- Ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity, for operating, maintaining and developing under economic

[122] Enemalta Corporation became Enemalta PLC as from the 27th August, 2014.

conditions a secure, reliable and efficient electricity distribution system so as to ensure continuity of electricity supplies in Malta with due regard for the environment and energy efficiency. In any event, it must not discriminate between system users or classes of system users.

- Providing system users with the information they need for efficient access to, including use of the system.
- When dispatching generating installations, giving priority to generating installations using renewable energy sources or waste or producing combined heat and power.
- Procuring the energy it uses to cover energy losses and reserve capacity in its system according to transparent, non-discriminatory and market based procedures.
- Dispatching generation plant and balancing the distribution system.
- Ensuring the availability of any necessary ancillary services, as prescribed by the Authority:
  - Rules for scheduling and criteria for dispatching that take into account contractual obligations;
  - Rules for balancing the electricity distribution system and for the charging of system users of their networks for energy imbalance and balancing services. Terms and conditions, including rules and tariffs, for the provision of such services shall be cost reflective:
- When planning the development of the distribution network, considering energy efficiency or demand-side management measures or distributed generation that might supplant the need to upgrade or replace electricity capacity. Demand-side management may include real-time management technologies such as advanced metering systems.
- When planning interconnections with other systems, giving special consideration to the specific geographical situation of Malta, the need to maintain a reasonable balance between the costs of building new interconnectors and the benefit to final customers of such interconnection, and if appropriate, ensuring that existing interconnectors are used as efficiently as possible.
- Setting and meeting quality of supply and network security performance objectives. The performance objectives shall be objective, transparent and non-discriminatory and be published: Provided that such performance objectives shall be subject to the approval and monitoring of the Authority.
- Taking into account the impact of any measure on the cost of electricity to final customers, before its adoption.

The role of the MRA, as the regulator, has the following duties, established by law:

- Approving, in accordance with transparent criteria, electricity generation, distribution and supply tariffs or their methodologies;
- Approving, in accordance with transparent criteria, the tariffs for the purchase of electricity by Enemalta where appropriate;
- Ensuring compliance of the distribution system operator, with their obligations under the regulations, other relevant legislation and Community legislation, including as regards cross-border issues;
- Cooperating in regard to cross-border issues with the regulatory authority or authorities of the Member States concerned and with the Agency;
- Complying with, and implementing, any relevant legally binding decisions of the Agency and of the Commission;
- Reporting annually on its activity and the fulfilment of its duties to the relevant authorities, the Agency and the Commission.
- Ensuring that there are no cross-subsidies between generation, distribution, supply and other activities;

- Monitoring the DSO investment plans, and providing in its annual report an assessment of them, including recommendations to amend them;
- Monitoring compliance with and reviewing the past performance of network security and reliability rules and setting or approving standards and requirements for quality of service and supply or contributing thereto together with other competent authorities;
- Monitoring the level of transparency and ensuring compliance of electricity undertakings with transparency obligations;
- Monitoring the time taken by the DSO to make connections and repairs;
- Helping to ensure, together with other relevant authorities, that the consumer protection measures are effective and enforced;
- Ensuring access to customer consumption data;
- Monitoring the implementation of rules relating to the roles and responsibilities of the DSO, suppliers and customers and other market parties;
- Monitoring investment in generation capacities in relation to security of supply;
- Monitoring technical cooperation between Community and third-country transmission system operators;
- Monitoring the implementation of safeguards measures;
- Contributing to the compatibility of data exchange processes for the most important market processes at regional level.

According to this, the distribution sector is regulated under a cost reimbursement regulatory model, where the DSO estimates the actual distribution costs, according to the approved methodologies, and the regulator fixes and approves the final tariffs. There's no a defined revision tariff timetable.

Key features of the regulatory regime are set out in the following table

Table 321: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Licence
Duration of tariff setting regime	Not fixed
Form of determination (distributor propose/regulator decide)	Distributor proposes/regulator approves
Scope for appeal regulatory decision	All decisions taken by the regulator may be appealed with the Administrative Review Tribunal

2.2. Main incentive properties of the distribution regulatory model

The system does not include regulatory incentives nor risk mitigation tools.

The key components of quality are described under the network code which provides technical standards for the use of the network and voltage regulation (incident management, operating planning, required information...). There is no interaction between the quality of service regulation and the tariff system, no system of financial compensation/penalties is implemented.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 322: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Regulatory Part of regulated retail tariff.
Regulatory asset base	Full cost recovery method. No components which do not correspond to distribution included in tariffs
Capital expenditure	SPV rentals, maximizing of return on owned properties, increasing efficiency and productivity
Approach to operating expenditure	Adequate maintenance, depreciation, interest payments on borrowings, and other interest payments, to create reserves
Form of WACC applied	NA Working capital management plan earmarked at reducing collection periods
Additional revenue items (where applicable)	Government compensation for street lighting, eco-reduction expense and feed-in tariffs expense , Moving to cheaper and cleaner energy solution (new independent power producers, conversion to natural gas, electricity interconnection with Italy(Sicily), closure of old steam plants), long term purchase agreements, increasing efficiency...

The full cost recovery method assumes the total variable retail tariffs should be equal to the sum of.

- Energy costs
- Wages
- Overheads
- Return on capital

After making appropriate deductions and/or add backs in respect of:

- Government subventions
- Fixed income charges
- Other services revenue

3. Tariffs for distribution services

The distribution tariffs are part of the regulated retail tariff:

- The retail tariff paid by consumers for electricity covers the costs and revenues pertaining to the operation of the distribution network apart from those related to the generation and supply activities.
- It applies the full cost recovery method in retail tariff.

3.1. Distribution tariffs

The cost allocation is a discretionary choice by the DSO as part of the overall tariff setting.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 323: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Retail tariffs cover distribution losses
Presence of uniform tariffs	Geographical tariffs are uniform
Presence of non-linear tariffs	Yes
Presence of regulated retail tariffs	Yes (All end user tariffs are regulated)
Presence of social tariffs	No. Although presence of energy vouchers

The three consumer classes described in section 1.2 herein are charged a retail tariff that covers also the distribution costs. The retail tariff is composed of

a) A fixed charge per annum
b) Tiered €c/ kWh tariff structure based on consumption level
c) €/kW maximum demand charge for connection services rated above 60A/phase

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 324: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	For connection ratings above 60A charges are deep the consumers and generators pay for the infrastructure up to the most suitable point of connection
	Methodology adopted	For connections above 60A/phase the DSO makes an estimate based on its cost but the client is free to

		procure the necessary works from a different source. An applicant who does not agree with the connection fee charged by the DSO can submit the complaint to the regulator and the regulator can issue decisions which are binding subject to appeal with the Administrative Review Tribunal
Hosting capacity	Scope to refuse connection	Household consumers and small non household consumers are protected by the universal service obligation. For consumers and generators the DSO can refuse connection only if that would entail unreasonable costs. In case of refusal of connection, the regulator is notified and can be asked by the party seeking connection to revert the DSO's decision.
	Requirements to publish hosting capacity	There is no obligation required to the DSO to publish the hosting capacity of its network.
	Targets and/or incentive schemes to enhance hosting capacity	There is no such incentive system.

4. Distribution system development and operation

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 325: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Distribution system development plan notified to the regulator but not approved nor published
- Key responsibilities for its development	NA
- Degree of integration with renewables plan	Takes into account RES plans on a site by site basis, and generically overall RES targets
- Relationship with consumption trends	It considers major developments foreseen during the next 5 years
- Relationship with quality of service targets	Limited relationship with QoS and network plans
- How trade-offs between network development and alternative technologies are treated	Smart metering technology is currently being implemented and is taken into account in the network plan, but no further consideration is given to smart grid technology
- Requirements to integrate cost benefit analysis	No cost benefit analysis is used to select the investments in the network development

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 326: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	Smaller embedded generators are not dispatched. Larger embedded generators 5MW are subject to dispatch by the DSO
Possibility to dispatch flexible loads	No possibility to dispatch flexible loads
Other sources of flexibility open to DSO	NA

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 327: Key approach to metering

Issue	Approach adopted
Discos role in metering	Full responsibility for metering, and own the meters
Monopoly services in the metering	Yes
Smart metering functionality	Yes.

As of 2013 there were 236248 smart meters installed in Malta, whose main features were:

- Quarter-of an hour measurement
- Remote reading
- Remote disconnection/reconnection of customers
- Remote control of the maximum power that can be withdrawn

A breakdown by customer category is illustrated below.

Table 328: Number of smart meters installed and remote billing functional by consumer category – by end of 2013

Customer category	Number
Residential	73257
Domestic	32310
Non-Residential	11816
Total	**117383**

The number of smart meters installed does not correspond exactly to the number of consumers with smart meters because consumers with an RES generator are normally provided with two smart meters: A generator meter and import/export meter. The information on the impact of smart meter roll out is not available.

Country Report – The Netherlands (electricity distribution)

1. Overview of to the distribution sector

DSOs in the Netherlands are required to be both ownership-unbundled and legally-unbundled.

The regulator is responsible for deciding on the final allowed revenues, tariff structures and connection charges.

1.1. Institutional structure and responsibilities

In the Netherlands there are 8 distributors supplying electricity to around 8 million customers covering an area of 337.000 km^2. Summary data on industry structure is set out below.

Table 329: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 customers	Exemption*	Share of total demand
Country	8	Yes	Yes	3	Yes Generators (Decentralised or larger centralised units) do not pay any transport/distribution tariff.	Unknown

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 330: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Proposes tariff levels	Proposes tariffs (and allocations of total income) to the NRA	Proposes charges (to the regulator for approval)
Government	Not involved	Sets the principal of the tariff structure	Not involved

NRA	Sets allowed revenues	Makes final decision on proposed tariffs	Sets charges

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The responsibility for setting distribution tariffs is as follows. The principle of the tariff structure is set by the minister of Economic Affairs (the Government). The tariff principles are then further detailed by the NRA in a 'tariff code' based on a proposal by the joint network operators, and in consultation with representatives of energy market players.

The DSO proposes the value of tariffs and the allocation of the total income. These final values and allocations are set by the NRA.

1.2. Key figures on revenue and tariffs

Distribution revenues in the Netherlands in 2013 were € 3210 million, broken down by the following activities:

- Distribution and connection – € 3000 million (93,5%)
- Metering (only small customers) – € 210 million (6,5%)

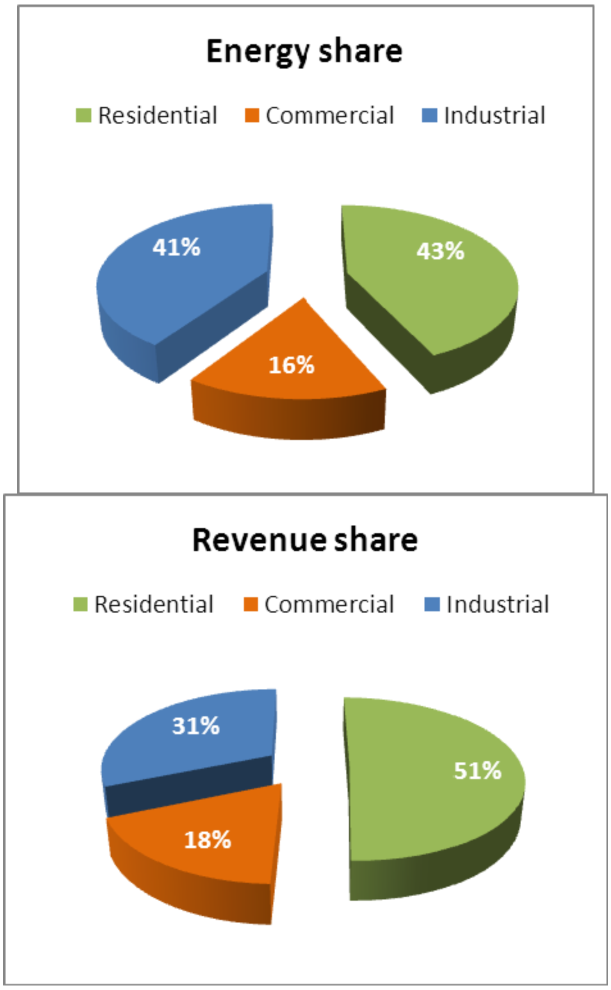
A breakdown of revenue by customer category, including information on available tariff components is set out in the table below.

Table 331: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenue Millions (€)
Household	KWh; kW	7500000	1612,500
Small industrial	KWh; kW	46000	83
Large industrial	KWh; kW	24000	510
Total	-	7570000	2205,500

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 68: Proportion of energy and revenue accounted by customer categories



These show a disproportionate share of costs borne by residential consumers, and to a lesser extent by commercial consumers. Industrial consumers provide a lower proportion of total revenues than might be expected based on their energy consumption.

Customer categories are defined as follows:

- Residential – typically defined as having a 3*25A connection and using 3750 kWh a year. However, the actual average usage has shifted (the average is now about 3500 kWh).
- Small industrial – with the assumption of 50 kVA, would fall in the category of 3*63A to 3*80A
- Large industrial – with the assumption of 4000 kVA, would fall in the (high end) category for Medium Voltage – Transport or Medium Voltage – Distribution category in the Netherlands

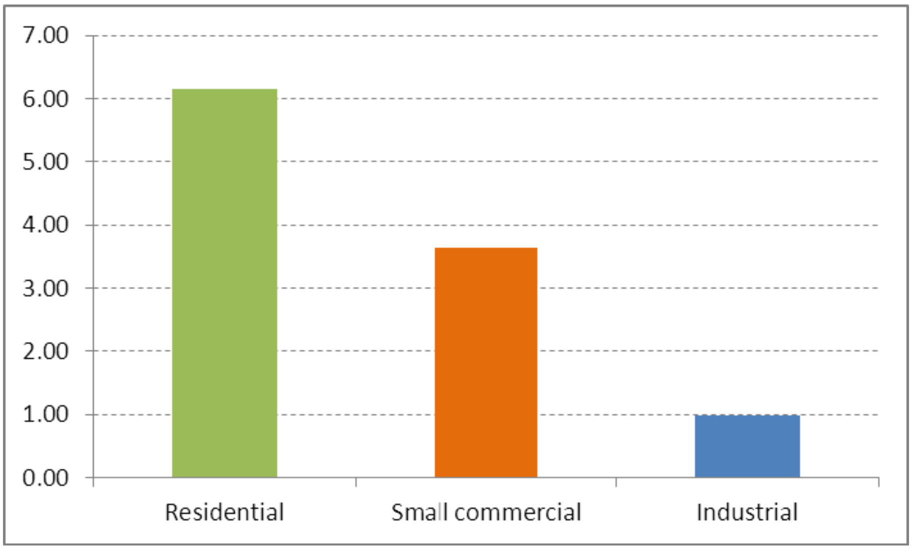
The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below:

Table 332: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Total
Residential	3500kWh	215		215
Small commercial	50MWh	55	1762	1807
Industrial	24000MWh	113441	125000	238441

The resulting average tariffs per kWh are illustrated below.

Figure 69: Average network charges (€cents/kWh), 2013



2. Regulation of distribution activities

The tariff-setting regime lasts for 3 years, and the regime focuses on total costs and outputs. DSOs propose the tariff levels and the regulator makes a final decision on

2.1. General overview

The distribution sector is regulated under a regime which focuses on output and total cost, and which is incentive-based.

The minor exception to the above-described regulatory regime is with regard to the costs of DSOs that are cost-reimbursed (that is, payments to other DSOs/TSOs and local taxes).

Another regulatory regime exception is in place for metering. For metering for small users there is a yearly CPI indexation on the 2005 metering tariffs. At the current time, the Dutch Competition Authority monitors the margin of the metering tariffs above the metering costs. The cumulative margin will be used to cover the costs of deploying smart meters.

The broad regulatory model is output-based. The output of the DSOs is based on the capacity/volume of the consumers connected, the electricity generation above demand per connection and the quality of service (frequency and duration of disruptions).

The basis of the income of the DSOs is set in regulatory periods through the x-factor and q-factor decisions, but can be adjusted in yearly tariff decisions.

Key features of the regulatory regime are set out in the following table

Table 333: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	No concessions
Duration of tariff setting regime	3 years
Form of determination (distributor propose/regulator decide)	The DSO submits a proposal. The regulator sets the final tariffs.
Scope for appeal regulatory decision	DSOs can appeal against any decisions related to tariff methodology, x- and q- factor decisions, and tariff decisions.

2.2. Main incentive properties of the distribution regulatory model

The broad regulatory model is output based. The output of the DSOs is based on the capacity/volume of the consumers connected, the electricity generation above demand per connection and the quality of service (frequency and duration of disruptions).

The basis of the income of the DSOs is set in regulatory periods through the x-factor and q-factor decisions, but can be adjusted in yearly tariff decisions.

A quality of service measure is in effect, which has the following characteristics:

- Technical standards are set in codes.
- The regulator reports quality of services performances annually.
- Quality of services interacts with the income of DSOs through the quality factor in the regulation method (the Q-factor).

At the same time the following tools are provided to mitigate risks:

- Profit sharing. The regulator has the choice to apply a gradual shift or an instant shift in tariffs from the previous regulatory period. That is, whilst a gradual and phased (multi-year) realignment towards efficient costs can be used, realignment towards efficient costs can also be done in one step (i.e. directly within one year) by the NRA. For the electricity DSOs the regulator applied an instant shift in the current period (2014-2016).
- Volume risk. Although the volume risk falls entirely on the DSOs, the largest part of a DSO´s revenues come from “per KW” tariff components (i.e. from rates based on capacity). The capacity tariff is applied to all connections ≤ 3*80A. Also, on bigger connections revenues are mainly or totally based on capacity. This contributes to reducing the volume risk.

- Intervention in the tariffs, by the regulator. The regulator can adjust the yearly tariffs during a regulatory period when realisations differ from expectations, when incorrect or incomplete information is used and when certain activities are no longer performed.

Key components of quality of service regulation include that technical standards are set in codes. The regulator reports quality of services performances annually. Quality of services interacts with the income of DSOs through the quality factor in the regulatory regime. There is a yardstick on quality of supply in place for electricity DSOs. This is based on the frequency and duration of the disruption and valuation of consumers. The performance of the DSO compared to the average performance leads to a bonus or a malus on the DSO´s income (q-factor).

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 334: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Output-based with cap, also includes incentives
Regulatory asset base	RAB is based on historic investments; new investments added annually and depreciation is subtracted. Adjusted for inflation. Allowed revenues are based on realised investments (use of yardstick/output regulation).
Capital expenditure	Totex approach used. DSO decides on Capex – Opex split.
Approach to operating expenditure	Totex approach used. DSO decides on Capex – Opex split.
Form of WACC applied	WACC with corporate tax rate included

The following formula is applied in determining the WACC:

$$WACC = \frac{K_E}{1-t_e} \cdot \frac{E}{D+E} + K_D \frac{D}{D+E} \cdot \frac{(1-t)}{(1-t_e)}$$

Where:

$K_E = r_f + \beta$ MRP is the cost of equity

MRP is the Market Risk Premium

K_D is the cost of debt

t is the debt tax shield

t_e is the corporate tax rate

3. Tariffs for distribution services

Distribution costs for decentralised (embedded) generation are covered in tariffs which are paid by end-users Tariffs vary by DSO, and also vary depending on the voltage level Connection charges are shallow in nature, and standard connection fees are generally used (which have been approved by the regulator)

3.1. Distribution tariffs

DSOs are obliged to propose cost-reflective tariffs. Requirements are placed in tariff codes. Among the requirements are:

- Allocations of costs to transport or connection;
- (Fixed) administrative or transport dependent costs;
- Grid voltage level;
- Cost put through from other grid levels (based on capacity demanded from each grid level).

There are several types of customers, depending mostly on voltage level and the presence of a transformer. Also, there is a differentiation for certain electricity demand profiles. Tariffs are differentiated in a fixed annual fee for (mostly) administrative costs and tariffs for transport-related costs. The tariffs of transport-related costs are based, depending on voltage level, on:

- contracted kW;
- peak kW;
- kWh (at MV; households do not pay an energy-related tariff component); and
- kVArh.
- For small consumers (≤ 3*80A) there is a capacity tariff based on their connection capacity.

There is also a separate nationally-uniform metering tariff in application for all customers except for large industrial (>3*80A) customers (for which the market for metering is liberalised).

Tariffs are set per DSO. Each same type of customer is charged a similar tariff (non-discrimination). Tariff components are linear within groups / categories.

There is no differentiation of the tariff components according to time of use. However, there is a differentiation (that is, lower tariffs) for large customers (on HV) who have:

(1) A small peak and nearly no usage in the rest of the year, or
(2) Use their maximum capacity nearly all the time during the year.

Distribution costs for decentralised (embedded) generation are covered in tariffs which are paid by end-users. Generators (that is, decentralised or larger centralised units) do not pay any transport or distribution tariff.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 335: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included in tariffs
Presence of uniform tariffs	The metering tariff is nationally-uniform, except for large industrial (>3*80A) customers (for which the market for metering is liberalised)
Presence of non-linear tariffs	No
Presence of regulated retail tariffs	No, regulation of retail tariffs was discontinued in 2004
Presence of social tariffs	No

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 336: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Uniform connection fees are used, except in the case of special connections. Charges are shallow in nature.
	Methodology adopted	Cost-reflective standard fees (for connection charges) are proposed by the DSOs and set by the regulator.
Hosting capacity	Scope to refuse connection	DSOs are generally not permitted to refuse connections
	Requirements to publish hosting capacity	The DSO is required to publish the hosting capacity of its network. This encompasses bottlenecks of capacity in the grid and grid expansion plans.
	Targets and/or incentive schemes to enhance hosting capacity	None

Regarding connection charges, only shallow charges are in effect for consumers and embedded generators. It is forbidden by law to have individual customers directly-compensate deep investments (other than the distribution tariffs).

For all connections up to 1 MVA and standard connections up to 10 MVA uniform connection fees apply. For special connections up to 10 MVA and connections larger than 10 MVA connection costs are computed case by case. Above 10 MVA a customer can have the connection be created and maintained by a third party instead of the DSO.

There exists an initial fee for the creation of the connection and a periodical fee for maintaining the connection. For long connections (>25m) a fee per meter is also applied. The uniform fees are fees per DSO. The uniform tariffs can differ for each DSO.

In determining the connection costs, the standard fees (which are proposed by the DSO and set by the regulator) should be cost-reflective.

The connections based on a case-by-case calculation have minimum requirements set in the tariff codes.

Customers have the opportunity to start a legal procedure against the DSO in the case of a conflict over the tariffs. The regulator will primarily deal with the conflict. After a decision of the regulator in the conflict, parties have an additional possibility to go to court.

DSOs are not allowed to refuse connections of consumers and generators.

The DSO is required to publish quality and capacity documents concerning the hosting capacity of their network. This encompasses bottlenecks of capacity in the grid and grid expansion plans. This information is public. It is custom (not binding) that the DSO presents location-specific plans upon connection requests.

Availability of capacity is not a criterion for the connection tariff calculation for connections up to 10 MV. In the case of a dispute, the regulator can demand the locational plans. In general the DSO is obliged to have sufficient capacity on the network and the regulatory also has a duty to connect all the renewable capacity that applies for connection.

4. Distribution system development and operation

Each DSO must publish a distribution planning document every two years.

All renewable plants self-dispatch; DSOs do not intervene in the dispatching process.

DSOs have full responsibility for managing and owning the meters, for small customers. Suppliers are responsible for the collection and validation of the data.

There are currently 600.000 smart meters installed in small customers´ homes in the Netherlands. The total amount of small customers is about 7.5 million, and there are targets in effect to have all small customers´ homes supplied with a smart meter by 2020.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 337: Approach to distribution planning

Issue	Approach
Form of distribution planning document	DSOs are obliged to compose a biennial Quality- and Capacity Report, equivalent to a distribution system planning document. The document describes all assets of network operators, and based on demand and generation prognoses, the required and planned investments.
- Key responsibilities for its development	DSOs are required to develop the document
- Degree of integration with renewables plan	There is a national target for renewable production. The target does not include specific details on the locations of projects, hence the target doesn´t directly influence network development plans. The link between the two plans can be made in case the Government grants a sitting permit, e.g. for a windfarm. The DSO in this region then includes this input in its generation and demand forecasts and adapts its network development plan accordingly.
- Relationship with consumption trends	The DSO includes consumption as an input in its generation and demand prognoses and adapts its network development plan accordingly. The input may come from various sources, e.g. proclaimed connection requests, and (amendments to) zoning plans for municipalities, provinces or states.
- Relationship with quality of service targets	Quality of service targets are explicitly taken as an input in the distribution development plan and, where relevant, the plan illustrates the relation between the investments and the quality objectives in the distribution area
- How trade-offs between network development and alternative technologies are treated	As the regulatory regime is output- and total-costs based an incentive is created for DSOs to invest and operate their networks as efficiently as possible. Where smart grids lead to a total cost decrease, the DSOs are incentivised to deploy them.
- Requirements to integrate cost benefit analysis	The results of the cost-benefit analyses used to select the network development investments and technologies, reported in the network development plan. In particular, the network development plans of the DSOs contain concrete examples of large investment projects to illustrate the cost-benefit analyses done by the DSO when deciding on investments. The examples contain only an overview of the analysis and are publicly available.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 338: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	Renewable plants self-dispatch;
Possibility to dispatch flexible loads	There are some early-stage pilot projects in effect in which DSOs test the capabilities of storage options / technologies.
Other sources of flexibility open to DSO	Demand response and flexibility provided by decentralised generation.

In the Netherlands, an arrangement of generators´ self-dispatching is in effect. DSOs do not dispatch generation.

With regards to whether DSOs have access to other sources of flexibility/regulation like batteries, capacitors, there are some small pilot studies where DSOs test the capabilities of storage.

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 339: Key approach to metering

Issue	Approach adopted
Discos role in metering	Full responsibility for managing and owning meters for small customers.
Monopoly services in the metering	DSOs are monopolists for managing and owning meters for small customers. Larger customers can procure metering services on the market.
Smart metering functionality	Quarter of an hour measurement Remote reading Local port to send real-time consumption information to local computer screens or computers.

DSOs have full responsibility for managing and owning the meters of small customers. Suppliers are responsible for the collection and validation of the data.

Plans have been approved to start the broad deployment of smart meters for small customers. In 2020 all small customers should have a smart meter. The smart meter can be refused; however, in pilot studies less than 2% of the customers refused a smart meter.

As of 2013 there were 600.000 smart meters installed in the Netherlands. Smart meters were distributed according to postal code, and hence the proportions of smart meters installed in each customer category is likely to be directly in-line with each customer category´s proportion of the total number of customers. The regulator does not know the number of smart meters installed per customer category.

The impact of smart meter roll out is estimated by the regulator as:

- A 6,4% consumption saving can be achieved when the customer has direct feedback via a display unit; and
- A 3,2% consumption saving can be achieved when the customer receives indirect feedback, for example through a website.

Country Report – the Netherlands (gas distribution)

1. Overview of to the distribution sector

Allowed distribution revenues in the Netherlands in 2013 were € 1270 million.

Customers categories are in the Netherlands are generally split as ´small customer´, and those which do not fall into the ´small customer´ category.

1.1. Institutional structure and responsibilities

In the Netherlands there are 9 distributors supplying gas to around 7,5 million customers (estimation). Summary data on industry structure is set out below.

Table 340: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Share of total demand
Country	9	Every DSO, aside from 2	All	2	Unknown

The responsibility for setting distribution tariffs ultimately lies with the regulator, which approves (or requests adjustments to) DSOs´ tariff proposals. The Government is not involved in setting distribution tariffs.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 341: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Proposes tariff level to the NRA	Proposes tariff level to the NRA	Proposes standard fees
Government	Not involved	Not involved	Not involved
NRA	Approves (or not) the DSOs´ proposals	Approves (or not) the DSOs´ proposals	Sets the fees

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory model uses yardstick competition (with a price cap) in the process of setting the amount of allowed revenues. The allowed revenue of a company is adjusted annually by (1+cpi-x+q), wherein cpi is the consumer price index, q represents the quality factor and x is the efficiency incentive.

The yardstick of allowed revenues is equal (except allowing for some regional variations) for all DSOs and is determined by the sector average cost per output, including an estimate of the growth in total factor productivity during the regulatory period. The yardstick competition system provides incentives to DSOs to improve their productivity; this happens because DSOs can achieve higher profits when they achieve productivities above the average level. Costs are determined based on average methodologies, and the regulator collects, on an annual basis, actual OPEX, investments, depreciation and the volumes of gas charged to customers.

1.2. Key figures on revenue and tariffs

Distribution revenues in the Netherlands in 2013 were € 1271 million, broken down by the following activities:

- Distribution and connection – € 1131 million (88,8%)
- Metering – € 140 million (11,2%)

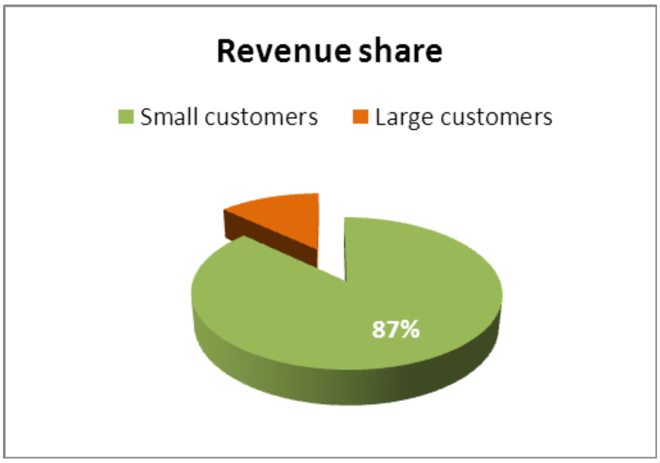
A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 342: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenue
Small customers	Administrative cost Transport-related capacity Connection cost Metering	6800000	€ 1110 million
Large customers	Administrative cost Transport-related capacity Connection cost	Unknown	€ 161 million
Total	-		€ 1271 million

The breakdown of distribution revenue by customer category is set out in the chart below. The regulator understands that volumes of gas consumed by each customer category are not publicly-available because the tariffs are based on capacity (not volume).

Figure 70: Proportion of revenue accounted by customer categories



Customers categories are in the Netherlands are generally split as ´small customer´, and those which do not fall into the ´small customer´ category. That is, there is no specific definition of typical small and large industrial consumers. These are defined as follows:

- Small customer – customers which have a G6 connection (capacity up to 10 m3/h) and using 2000 m3 of gas ('Groningen standard') per year. Actual average usage has shifted however (the average is now about 1650 m3).
- Non-small customer – all customers which do not fall under the ´small customer´ category

2. Regulation of distribution activities

The regulatory model is incentive-based, and focused on outputs and total costs. The regulatory regime is 3 years duration.

DSOs are obliged to propose cost-reflective tariffs.

Mitigation mechanisms are in place concerning volume risks, tariff adjustments and profit sharing.

2.1. General overview

The role of the DSOs in the Netherlands is to propose allowed revenues and distribution grid tariffs, and the NRA sets the final versions of the maximum tariffs to be applied. The Government is not involved in this process.

The Dutch regulatory model is focused on output and total cost, and is also incentive-based. The minor exception is with regard to the costs of DSOs that are cost-reimbursed (local taxes).

There is ex-ante regulation (3-year regulatory period) with fixed yearly tariffs. The DSO takes on the volume risk (mostly capacity based).

The broad regulatory model is output based. The output of the DSOs is based on the capacity/volume of the consumers connected. The basis of the income of the DSOs is set in regulatory periods through the x-factor decisions, but can be adjusted in yearly tariff decisions.

In general the regulator does not give specific approval to investments (due to output regulation). The ex-ante regulation includes an estimation of investments.

The DSO is obliged to propose cost-reflective tariffs. Requirements are placed in tariff codes. Among the requirements are: the allocation of costs to transport or connection; (fixed) administrative or transport dependent costs; grid pressure; and cost pass through from other grid levels.

Key features of the regulatory regime are set out in the following table:

Table 343: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	N.a.
Duration of tariff setting regime	3 year regulatory period, with fixed yearly tariffs
Form of determination (distributor propose/regulator decide)	DSO proposes and the regulator decides and finalises

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- There is ex-ante regulation (3 year regulatory period) with fixed yearly tariffs. The DSO has volume risk (mostly capacity based).

Quality of service performance is assessed, but it does not impact on income; in other words, it does not act as an incentive.

At the same time the following tools are provided to mitigate risks:

- Profit sharing. The regulator has the choice to apply a gradual shift or an instant shift in tariffs from the previous regulatory period. That is, whilst a gradual, phased realignment towards efficient costs can be used, realignment towards efficient costs can also be done in one step by the NRA. For the gas DSOs, the regulator applied a gradual shift in the current period (2014-2016).
- Volume risk. Whilst the volume risk is carried entirely by the DSOs, the largest part of the revenues come from “per m3/hour” tariff components (i.e. from rates based on capacity). This contributes to reducing the volume risk.
- Tariff adjustment. The regulator can adjust the yearly tariffs during a regulatory period when realisations differ from expectations, when incorrect or incomplete information is used and when certain activities are no longer performed.

2.3. Determination of cost of service parameters

The Dutch regulatory model is focused on outputs and total costs, and includes incentives. Tariffs are fixed for one year, as set through ex-ante regulation (which has a 3-year period).

ACM can adjust the yearly tariffs during a regulatory period when realisations differ from expectations, that is, when incorrect or incomplete information is used and when certain activities are no longer performed.

The approach to determining key cost of service parameters are summarized in the following table.

Table 344: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Price cap, with efficiency incentives
Regulatory asset base	The RAB of DSOs is set in regulatory periods based on the capacity/volume of customers connected and through the x-factor decisions (which can be adjusted in yearly tariff decisions).
Capital expenditure	Annual benchmarking based on real costs
Approach to operating expenditure	Annual benchmarking based on real costs
Form of WACC applied	Real WACC, before tax
Additional revenue items (where applicable)	

The following formula is applied in determining the WACC:

$$WACC = \frac{K_E}{1-t_e} \cdot \frac{E}{D+E} + K_D \frac{D}{D+E} \cdot \frac{(1-t)}{(1-t_e)}$$

Where:

$K_E = r_f + \beta$ MRP is the cost of equity

MRP is the Market Risk Premium

K_D is the cost of debt

t is the debt tax shield

t_e is the corporate tax rate

3. Tariffs for distribution services

The regulator sets the allowed tariffs, following a proposal submitted by each DSO.

Tariffs are geographically-uniform, linear, not regulated and social tariffs are not used.

Connection charges are shallow in nature, and DSOs are generally not allowed to refuse new customer connections.

3.1. Distribution tariffs

In the tariff-setting process, the DSO submits a proposal and the regulator sets the final tariff values.
DSOs are obliged to propose cost-reflective tariffs and the requirements are placed in tariff codes. Among the requirements are:

- The allocation of costs to transport or connection;
- (Fixed) administrative or transport dependent costs;
- Grid pressure; and
- Cost pass-through from other grid levels.

The tariffs are set per DSO. Each same type of customer is charged a similar tariff (there is non-discrimination). Metering tariffs for small users are nationally-uniform; for large industrial consumers metering tariffs are liberalised. There is no time-of-use differentiation of tariffs, and all tariff components are linear within groups and categories.

Renewable generation are charged distribution tariffs similar to other users. Currently this is being reviewed by the Ministry of Economic Affairs.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 345: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Charges as part of the distribution tariffs
Presence of uniform tariffs	Yes, except for large industrial (>3*80A) customers (for which the market for metering is liberalised)
Presence of non-linear tariffs	No
Presence of regulated retail tariffs	No, it has been an open market since 2004
Presence of social tariffs	No

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 346: Summary of key issues relating to connection charges

	Issue	Approach

Determination of charges	Type of charges (shallow/deep)	Shallow
	Methodology adopted	For all connections up to 40m3/h uniform connection fees apply. Above 40m3/h only a uniform connection fee applies to the connection point on the grid. The other components (pipe, security before the installation) are computed on a case-by-case basis.
Hosting capacity	Scope to refuse connection	In principle all consumers have a right to have a connection, and connected to the closest suitable location on the grid. There is an exception for remote locations where it is not feasible to extend the grid or to achieve a connection.
	Requirements to publish hosting capacity	DSOs are required to publish quality and capacity documents of the grid
	Targets and/or incentive schemes to enhance hosting capacity	No specific measures, but DSOs are obliged to ensure they have sufficient capacity on the network.

Above 40m3/h a customer can have the connection (except for the connection point on the grid) created and maintained by a third party instead of the DSO.

There is an initial fee for the creation of the connection and a periodical fee for maintaining the connection. For connections of over 25m a fee per meter is also applied.

Charges are shallow in nature, for both gas consumers and embedded generators. It is forbidden by law to have individual customers directly compensate deep investments.

In determining the connection fees, the standard fees proposed by the regulator should be cost-reflective. The connections based on a case-by-case calculation have minimum requirements set in the tariff codes.

Customers may initiate legal procedures against the DSO in the case of a conflict over tariffs and the regulator will primarily deal with the conflict. After the regulatory delivers its decision the involved parties may opt to take the matter to court if they are still unsatisfied with the result.

DSOs are required to publish quality and capacity documents of the grid. These encompass capacity bottlenecks in the grid and grid expansion plans. This information is publicly-available. It is not required to publish all available capacity on the grid; it is customary practice (but not binding) that the DSO presents location-specific plans upon connection requests.

4. Distribution system development and operation

DSOs are required to develop a biennial Quality and Capacity Report; the document is reviewed and approved by the NRA. Targets for quality of service are explicitly taken as an input in the distribution development plan and, where relevant, the plan illustrates the relationship between the investments and the quality objectives in the distribution area.

DSOs have full responsibility for managing and owning the meters, for small customers. Suppliers are responsible for the collection and validation of the data.

As of December 2013 there were 600.000 smart meters installed in the Netherlands.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 347: Approach to distribution planning

Issue	Approach
Form of distribution planning document	DSOs are required to develop a biennial Quality and Capacity Report. This document must meet the Ministerial Regulations in Relation to Quality Aspects of Electricity Grid and Gas Network Management. It is formulated and then provided to the NRA for the NRA´s review and assessment.
- Key responsibilities for its development	DSOs are required to develop the document; the NRA approves
- Degree of integration with renewables plan	N.a.
- Relationship with consumption trends	No direct relationship
- Relationship with quality of service targets	Included as an explicit input.
- How trade-offs between network development and alternative technologies are treated	Generally, as the regulatory model is output and incentive based, DSOs are incentivised to invest and operate the network as efficiently as possible, meaning that DSOs are incentivised to invest in smart grid and alternative technologies where there is a resulting regulated cost decrease.
- Requirements to integrate cost benefit analysis	Yes, the network development plans of the DSOs contain concrete examples of large investment projects to illustrate the cost-benefit analyses done by the DSO when deciding on investments.

Network operators are obliged to compose a biennial Quality and Capacity Report. The document describes all the assets of network operators, and based on demand and generation prognoses, the required and planned investments.

The network development plan does not have to include any information on environmental policies. However, the DSOs do have to monitor the release of methane into the atmosphere (they use a model for this, which was developed by a research institution) and report on this to the Ministry in a yearly report.

Targets for quality of service are explicitly taken as an input in the distribution development plan and, where relevant, the plan illustrates the relationship between the investments and the quality objectives in the distribution area. For example, this can be the case with regard to investments to reduce voltage issues in certain areas.

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 348: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs are fully responsible for managing and owning meters for small customers; for large customers, metering services can be procured on the market.
Monopoly services in the metering	For small customers, DSOs are monopoly service providers.
Smart metering functionality	Use hourly measurement; have a default remote reading capability; cannot be remotely disconnected and reconnected, nor have remote control of the maximum gas flow. The smart meters do allow the remote operation of the consumers´ appliances.

DSOs have full responsibility for managing and owning the meters, for small customers. For large customers, where metering services can be procured on the market, the suppliers are responsible for the collection and validation of the data.

As of December 2013 there were 600000 smart meters installed in the Netherlands. This is of a total small customer base of around 7,5 million. The following preliminary information on the impact of smart meter roll out is available.[123] No specific analysis has been undertaken on the per-household average cost saving resulting from the installation of a smart meter.

Table 349: Effects from the smart meters deployment.

DSO	Total number of households	Number of households with a SM	Gas consumption reduction
All DSOs considered together	7500000	600000	0,9%

[123] Rijksoverheid, 2014. Received from: file:///C:/Users/A406918/Downloads/kamerbrief-over-besluit-grootschalige-uitrol-slimme-meters.pdf

Country Report – Poland (electricity distribution)

1. Overview of the distribution sector

There are 5 large DSOs and 164 smaller-scale ´energy enterprises´ which effectively act as DSOs in their respective jurisdictions.

The regulator determines the allowed revenue; the DSOs propose their respective tariff levels which are implemented subject to approval being received from the regulator.

Allowed revenue calculations and tariff setting is exclusively the role of the DSOs and the regulator; the government is not involved.

1.1. Institutional structure and responsibilities

In Poland there are 169 DSOs supplying electricity to around 16,8 million customers covering 312884 km^2. Summary data on industry structure is set out below.

Table 350: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	169	separated from energy trading companies	Yes	164	Yes, embedded generators do not pay tariffs	9,2%
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

A concession regime is in place for DSOs´ undertaking of activities, under which the energy law states that concessions should last from 10 to 50 years, although most of them are issued for 10-year periods. Concessions are granted to those who hold rights to distribution assets (ownership, leasing, other).

The concession owner mostly acts as a DSO on their own physical distribution network. There is a possibility that the grid proposed to be used by the concession owner is operated by another operator which also has a concession for distribution. The tariff is set and approved for the enterprise which is the owner of the grid. The cost of operating the grid is a subject of contract between the owner of the grid and operator.

Tariffs are set by the DSO and are approved by the President of ERO, the regulator. The Law stipulates that there should be no cross-subsidies. The maintenance and modernisation of the grid, taxes and depreciation should be covered by a fixed distribution fee. Nevertheless, some parts of the fixed costs are covered by a variable distribution fee (which is calculated mostly in order to cover losses) due to the need to protect the customers. The share of fixed fees is determined by the President of ERO.

The NRA, in the process of agreeing a development plan, sets a justified level of expenditures for connection to the network. In addition, the NRA - based on data from the DSO development plans, including the level of investment expenditures, the number of consumers and connected load - periodically verifies the level of connection fees for consumers connected to the LV grid.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 351: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Proposes revenues to the NRA	Proposes tariff structure to NRA	Not involved
Government	Not involved	Not involved	Not involved
NRA	Approves allowed revenues	Takes decision on tariff structure based on DSO proposal	Defines main principles

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

Tariffs are set by the DSO and approved by the President of ERO, the regulator. The tariffs are published in the ERO bulletin.

1.2. Key figures on revenue and tariffs

The regulated revenues of the five large DSOs in Poland was 17,8 billion PLN. The allowed distribution revenue is approved according to justified costs and the justified level of RoC. There is no split of allowed revenue for different activities.

Customers are categorised based on various factors, including voltage, contractual load power and consumption in time zones (1,2 or 3).

Residential customers are connected to the grid independent of voltage level, but mostly to the LV network.

Industrial customers could be:

- “large” – A group -HV
- “medium”-B group -MV – mostly: contractual capacity > 40 kW, rarely: contractual capacity < 40 kW

- “small” C group – LV, with : contractual capacity up to 40 kW (C1 groups) and higher than 40 Kw (C2 groups) .

The tariff components applied to industrial customers include: distribution rates: variable and fixed rate components, quality rate (variable), transition fee (fixed), subscription fee (fixed PLN/month). Variable rates are in PLN/MWh or PLN/kWh, fixed (except subscription fee) in PLN/kW/month.

The tariff components applied to residential customers include: variable and fixed rate components, quality rate (variable), transition fee (fixed), and subscription fee (fixed). Variable rates are calculated in PLN/kWh; and fixed rates are calculated in PLN/month.

In 2013 the following numbers of customers were connected to the respective voltage networks:

- HV – 379 customers
- MV – 34.518 customers
- LV – 1.619.348 customers
- Residential – 15.150.566 customers
- Others (temporary connected) – 5.838 customers

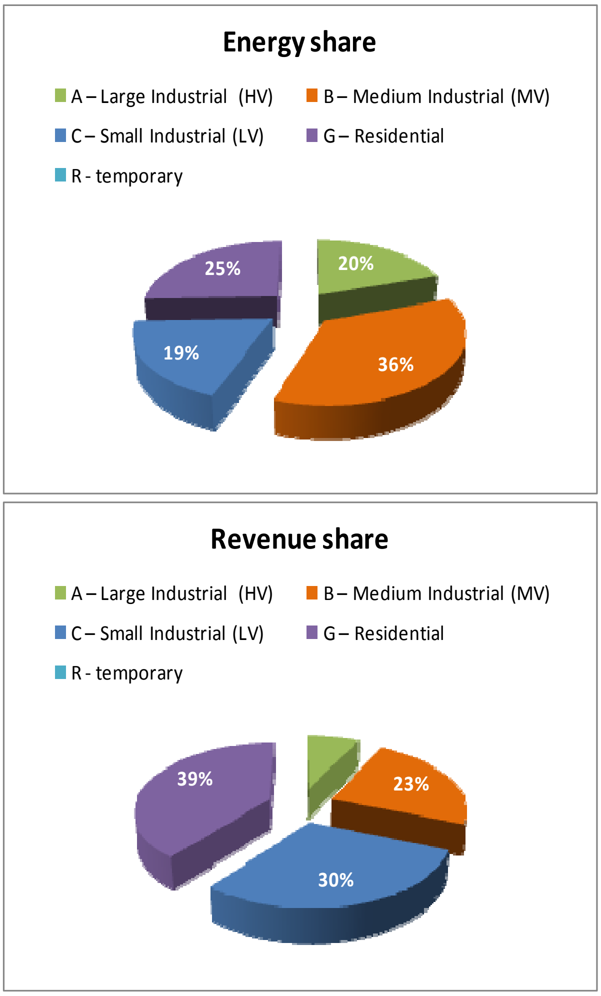
A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 352: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenue (PLN million)
A – Large Industrial (HV)	KWh, kW	379	1327
B – Medium Industrial (MV)	KWh, kW	34518	4165
C – Small Industrial (LV)	KWh, kW	1619348	5325
G – Residential	KWh, kW	15150566	6974
R - temporary	KWh, kW	5388	8
Total	KWh, kW	16810649	17799

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 71: Proportion of energy and revenue accounted by customer categories



These show a disproportionate share of costs borne both residential and small industrial consumers in relation to their respective energy shares. Large industrial consumers on the other hand, consume one fifth of total energy consumption but only contribute 8% of the total revenues.

The typical network tariff in 2014 has been calculated below for the following classes of industrial customers:

- A - “large” HV
- B - “medium” MV – mostly: contractual capacity > 40 kW, rarely contractual capacity < 40 kW:
- C - “small” – LV, with: contractual capacity up to 40 kW (C1 groups) and higher than 40 kW(C2 groups)

The tariff components applied to industrial customers: distribution rates: variable and fixed rate components, quality rate (variable), transition fee (fixed), subscription fee (fixed PLN/month).

The tariff components applied to residential customers include:

- Variable and fixed rate components
- Quality rate (variable)
- Transition fee (fixed)
- Subscription fee (fixed).

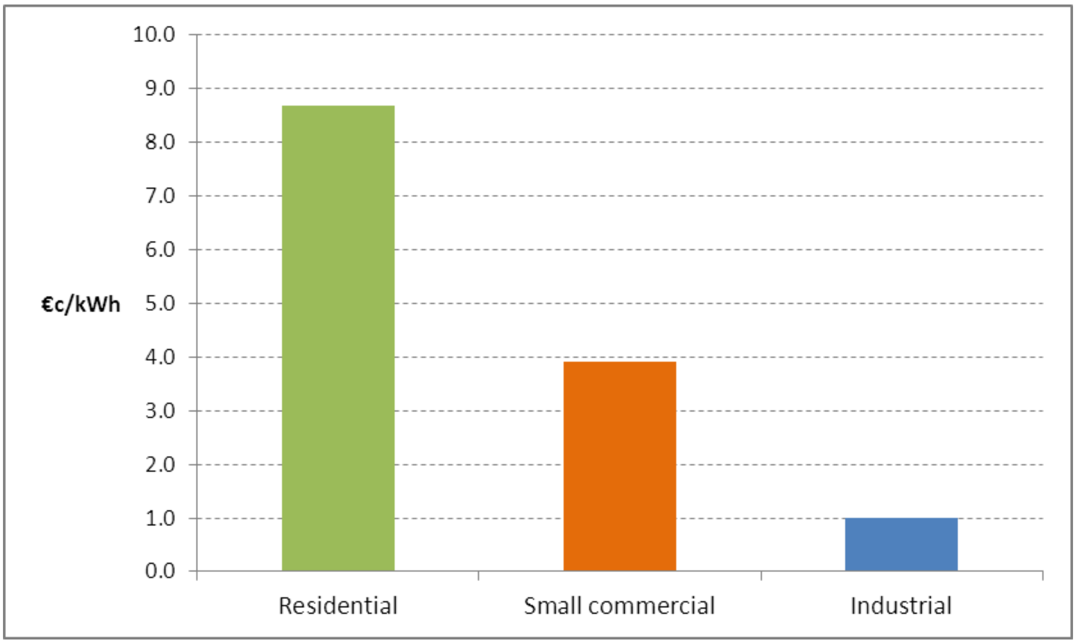
A representative network tariff in 2013 for residential, small and large industrial customers is illustrated below:

Table 353: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Demand and reactive charges	Total
Residential	3500kWh	56	148		204
Small commercial	50MWh	1250	709		1959
Industrial	24000MWh	2427	230769	11059	244255

The resulting average tariffs per kWh are illustrated below.

Figure 72: Average network charges (€cents/kWh), 2013



An example of network tariffs applied in 2013, by PPC Rokita SA is included as Annex 1.

2. Regulation of distribution activities

Regulatory revenues are set under a mixed approach, wherein a revenue cap is used as well as certain performance incentives.

The regulatory regime has 4 year duration.

Sharing mechanisms for under-spend are in effect.

2.1. General overview

Key features of the regulatory regime are set out in the following table.

Table 354: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	The law provides that concessions last from 10 up to 50 years although most of them are issued for a 10-year period. Concessions are granted, after administrative procedure, to those who hold rights to distribution assets (ownership, leasing, other).
Duration of tariff setting regime	The OPEX and losses model is set for 4 years regulatory period 2012-2015. The return on capital method / regime is set for a 4-year period (currently 2011-2015), but RoC is updated annually. Other components of costs and revenue are set every year.
Form of determination (distributor propose/regulator decide)	Tariffs are set by the DSO and approved by the regulator. A fixed distribution fee is used to cover the maintenance and modernisation of the grid, taxes, depreciation. Nevertheless some part of the fixed costs is covered by a variable distribution fee (which is calculated mostly in order to cover the losses) due to the need to protect the customers. The share of fixed fees is determined by the regulator.

The broad regulatory model in effect in Poland can be characterised as being mixed, with the model based partly on revenue cap regulation. The regulatory model provides for performance incentives. In particular:

- The OPEX level is changed by the RPI-X method during each regulatory period;
- Losses indicators (ratio for voltage level) are also set for each regulatory period; and
- During the regulatory period, the DSO can profit from savings resulting from efficiency achievements in DSO activities. Costs are reviewed at the end of each regulatory period.

Allowed revenue assessments are based on assumptions of three outputs:

- GWh delivered through the distribution network;
- Number of consumers connected; and
- Capacity of consumers connected.

The electricity tariff is composed of various sub-components, namely:

- Variable component of distribution fee (mostly cost of losses and some amount of fixed costs).
- Quality fee (costs of maintaining the system-related standards of quality and reliability of current electricity supplies).
- Fixed component of distribution fee (maintaining and modernisation of the grid, taxes, depreciation).

- Transitional fee (costs resulting from termination of PPA)
- Subscription fee (costs of reading and inspecting the metering systems).

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Operating expenditure efficiency requirements (DSOs allowed to keep a portion of savings resulting from efficiency improvements)
- Quality of service factor will be introduced in 2016

At the same time the following tools are provided to mitigate risks:

- Cost reviews are undertaken at the end of each regulatory period
- Volume risk is taken by the DSOs, but planned volume for tariff in the next year can be adjusted according to trend (in volume) in the previous few years.
- A DSO can ask for a correction of the tariff during the year of its validity.

Regarding quality of service regulation, the regulatory model will change from 2016 onwards. The model will take into account quality of service issues. It is currently under preparation.

2.3. Determination of cost of service parameters

A mixed model is used, wherein costs of service are based partly on revenue cap regulation and the return on capital (WACC). The model also includes an efficiency improvement requirement applied to OPEX (via the RPI-X method).

Advanced Metering Infrastructure investments are remunerated by higher WACC than “usual” grid investments.

A benchmarking model is used to allow a comparison of DSOs´ costs with other relevant cost references; the model is based on Bayesian inference for regulatory period 2012-2015 for OPEX and losses. A benchmarking model for CAPEX is also used.

The approach to determining key cost of service parameters are summarized in the following table.

Table 355: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue cap based with efficiency adjustments
Regulatory asset base	The deprival value method is used to set the RAB. In the subsequent years the RAB is updated due to investments, deprecation and connection fees
Capital expenditure	Total expenditure benchmarking
Approach to operating expenditure	Total expenditure benchmarking
Form of WACC applied	Calculation of WACC (pre-tax)
Additional revenue items (where applicable)	Service quality measures will be implemented from 2016 onwards

The following formula is applied in determining the WACC:

$$WACC(pre\text{-}tax) = rd \times D/(D+E) + re/(1-t) \times E/(D+E)$$

where:

- rd – cost of debt,
- re – cost of equity,
- D – debt,
- E – equity,
- t – tax rate.

The debt leverage ratio is set for every year of period covered by WACC model, i.e. 2011-2015. The debt share increases every year in this period.

3. Tariffs for distribution services

Embedded generators are not required to pay distribution charges.

Tariffs vary by DSO and so-called “special” (large-volume) end-users pay a smaller quality fee and transitional fee.

Connection charges are calculated based on cost of the work involved, and are shallow in nature.

3.1. Distribution tariffs

Distribution tariffs are set by the DSOs and the regulator has responsibility to approve them or not. In the allocation of distribution costs to the tariffs, the principle that no cross-subsidies of distribution costs is applied. Tariffs are composed of a fixed and a variable distribution fee.

Within the tariffs, the following cost factors are covered by the fixed fee: grid maintenance and modernisation costs, taxes, and depreciation. Nevertheless, some parts of the fixed costs are covered by the variable distribution fee. The variable distribution fee is calculated mainly with the objective of covering the losses. The regulator determines the share of fixed fees within tariffs.

There are 4 classes of electricity consumers:

- HV (A group),
- MV(B group),
- LV non-residential (C group),and
- Residential (household)-regardless of voltage but most of them are connected to LV grid (G group).

Consumers are charged related to the following components:

- Per kWh charges (PLN/kWh) - variable and quality rates (all end-users). This is mainly the cost of losses and some amount of fixed costs;
- Per kW charge (PLN/kW/month) – fixed component of distribution rates and transitional fee (rate of charge resulting from termination of PPA)- (A,B,C groups end-users). This is mainly the costs of modernising the grid, taxes and depreciation. Transitional fees are costs which have resulted from the termination of PPAs;
- Per end-user (PLN/month) charge - fixed component of distribution rates and transitional fee (rate of charge resulting from termination of PPA) (G groups end-users). This is mainly the costs of modernising the grid, taxes and depreciation. Transitional fees are costs which have resulted from the termination of PPAs; and
- Per end-user – (PLN/month) subscription fee (all end-users). Subscription fees cover the costs of reading and inspecting the metering systems.

Tariffs are proposed by each of the 5 DSOs ("Big") and approx. 160 smaller DSOs - so-called industrial energy enterprises.

The per-KWh component of tariffs is different in peak and off-peak time (2 or 3 time zones). The zones are defined in different ways. For example, for the A23 tariff group (big industrial end-user HV) in April to September:

- I zone, morning (antemeridian) peak: 7-13,
- II zone, afternoon peak 19-22, and
- III zone 13-19 and 22-7.

Tariff variable components are linear. But for the transition fee (fixed rate) for groups G (residential), the tariff differs depending on the amount of purchased energy. For instance, in 2013 the G group had the following (non-linear) transitional fee components in effect.

Energy consumption annually	Transitional fee PLN/month
Less than 500 kWh	0,08
From 500 to 1200 kWh	0,36
More than 1200 kWh	1,13

No distribution tariffs are charged to embedded generators.

Distribution losses are charged as part of the distribution tariffs, via the per-KWh component of the distribution tariff (variable component of distribution fee) includes the cost of losses.

Only the supply tariff for households (energy retail trade) is regulated (other tariffs are not regulated). Nevertheless, every end-user has possibility to switch supplier.

So called "special" end-users pay a smaller quality fee and transitional fee. "Special" end-users are end-users who consume more than 400 GWh annually (and use not less than 50% (in case of quality fee) or 60% (in case of transitional fee) of contract capacity and the cost of energy is not less than 15% of production value).

No social tariffs are implemented. Social end-users can receive monthly fixed rate allowance (which is set for household – differentiated according to amount of inhabitants of household). The allowance is paid by the municipality.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 356: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Covered by the variable component of the distribution fee
Presence of uniform tariffs	No – tariffs vary by DSO
Presence of non-linear tariffs	All components are linear, apart from the transition fee component
Presence of regulated retail tariffs	The supply tariff for households is regulated; other tariffs are not regulated
Presence of social tariffs	No

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 357: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Connection fees are calculated on the basis of expenditures incurred only in relation to the connection; these are shallow costs.
	Methodology adopted	In relation to the methodology used to determine connection costs, the NRA agrees a development plan that sets a justified level of expenditures for connection to the network.
Hosting capacity	Scope to refuse connection	The DNO is required to connect those that require connection and which meet the relevant technical specificities
	Requirements to publish hosting capacity	The DSO is required to publish information on the value of the total available connection capacity, as well as planned changes to these values in the next five years from the date of publication, for the entire enterprise network. It should update this publication at least once a quarter.
	Targets and/or incentive schemes to enhance hosting capacity	No specific measures in place, but the allowed return on capital covers grid investment costs

Connection fees are calculated on the basis of expenditures incurred only in relation to the connection (shallow costs). Expenditures for the expansion and modernization of the network are not included in the fee calculation.

Broadly speaking, the fee for the connection to the grid is calculated according to the following rules:

- The fee for the connection to electricity grid of a rated voltage of more than 1 kV and not higher than 110 kV, except for the connection of sources and grids, shall be determined on the basis of a fourth part of the investment incurred in relation to the connection,
- The fee for the connection to an electricity grid of a rated voltage not higher than 1 kV, except for the connections to sources or grids, shall be determined on the basis of the fee rates included in the tariff, calculated on the basis of a fourth part of average annual costs of investment in the construction of the grid sections used to connect such entities, specified in the development plan; those rates may be calculated allowing for the connection power, a unit of length of the grid used for connecting or the type of that grid section,
- The fee collected for the connection of sources cooperating with the grid or the grids of energy enterprises whose activity consists in the transmission or distribution of energy is calculated on the basis of the actual costs of investments incurred in relation to the connection, except for:
  - Renewable energy sources with an installed electrical capacity of no more than 5 MW and cogeneration units with an electrical capacity installed capacity below 1 MW, shall be subject to a fee equal to a half of the fee calculated on the basis of the actual costs of investment incurred,
  - Micro-installations, for which the connection to the electricity distribution network are not charged.

In relation to the methodology used to determine connection costs, the NRA agrees a development plan that sets a justified level of expenditures for connection to the network.

In addition, the NRA - based on data from the DSO development plans - level of investment expenditures, the number of consumers, connected load – periodically verifies the level of connection fees for consumers connected to the LV grid.

Energy enterprises whose activities consist of the transmission and distribution of gaseous fuels or electricity have an obligation to conclude a grid connection agreement with entities requesting connection to the grid, on terms of equal treatment, if it is technically and economically feasible to supply energy or fuels and the applicant meets the requirements for being connected to the grid and taking supply. Should the energy enterprise refuse to conclude a grid connection agreement, it is obliged to notify the Regulator and the entity requesting the connection in writing of the refusal without delay, stating the reasons for the refusal.

The energy enterprise (DSO) engaged in the transmission or distribution of electricity is required to publish information on the value of the total available connection capacity, as well as planned changes to these values in the next five years from the date of publication, for the entire enterprise network at rated voltages above 1 kV, broken down by power stations or groups in the network with a rated voltage of 110 kV and higher. The enterprise updates the information at least once a quarter, taking into account the expansion made, the modernization of the network and the connections both established and in progress, and publishes this on its website.

The DSO is assumed to have a duty to connect all the renewable capacity that applies for connection.

Within the regulatory model, the allowed return on capital covers grid investment costs, and is employed as an incentive for the DSO to invest in the grid development. The regulator has also introduced an incentive to invest in smart metering, through allowing an increased return on capital for investments that meet the requirements set by the regulator.

4. Distribution system development and operation

Each DSO prepares a development plan which looks ahead by at least 5 years. These are updated every 3 years.

DSOs can enter into bilateral agreements with demand sources and embedded generators for dispatch and control purposes.

DSOs have a monopoly on metering activities and are responsible for the distribution and rollout of smart meters; however, they are not bound to achieve specific meter rollout targets. The rollout of smart meters in Poland is in the preliminary stages.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 358: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Each DSO must publish a development plan which looks at least 5 years ahead. The plan should be updated every 3 years. All DSOs are required to do this, except those which distribute electricity to less than 100 customers (and for which the DSO provides less than 50 GWh of electricity annually).
- Key responsibilities for its development	The document is developed by each DSO, following agreement with the regulator on its scope.
- Degree of integration with renewables plan	DSOs are required to connect renewable energy sources which apply for connection. These sources are included in the development plans.
- Relationship with consumption trends	Plan takes consumption trends into account.

Issue	Approach
- Relationship with quality of service targets	Under development – quality of service targets due to be introduced in 2016.
- How trade-offs between network development and alternative technologies are treated	DSOs are not required to explain (in the plan) the rationale behind these trade-offs.
- Requirements to integrate cost benefit analysis	The network development plan reports only the decisions of the DSOs. The analyses on which those decisions are based are not public.

The energy enterprises involved in the transmission or distribution of electricity prepare development plans for their area of operation in terms of satisfying current and future demand for electricity, for a period not shorter than 3 years, excluding:

- Transmission System Operator (TSO), which prepares a development plan for a 10-year period
- Distribution System Operators (DSOs), which prepare development plans for at least 5 years

The plans are updated every 3 years.

Draft development plan shall be agreed with regulator, except for the development plans of energy enterprises involved in the distribution of electricity to less than 100 customers to whom the energy enterprise provides annually less than 50 GWh of electricity.

The support system for RES is mainly based on the obligation to purchase electricity generated in the source by suppliers and to purchase the green certificates. DSOs are required to connect renewable energy sources which apply for connection. These sources are included in the development plans.

The forecast electricity consumption volume change of electricity supply is included in the Balanced Scorecard of the development plan.

The development plan does not explicitly illustrate the relationship between each (type of) investment and the benefits in terms of increased quality of services. Currently, work is being undertaken on the introduction of a quality regulation model.

The development plan should ensure long-term maximization of the efficiency of capital expenditures and costs incurred by energy enterprises, so that in particular years the capital expenditures and costs would not cause excessive increase in prices and fee rates for the supply of energy, while ensuring continuity, reliability and quality of supply.

Regarding the results of analyses used to select the network development investments and technologies, the network development plan reports only the decisions of the DSOs. The analyses on which those decisions are based are not public. For parts of the investment, DSOs provide justification for the necessity of their implementation (e.g. due to age), or NPV, IRR.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 359: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	DSOs are allowed to dispatch any generation units connected to the distribution network except for generation units with an installed capacity of 50MW or more.
Possibility to dispatch flexible loads	DSOs do not dispatch any generation units connected to their grid unless (and only if) there is specific bilateral agreement between the DSO and generator. DSOs may curtail flexible loads if the safe operation of the grid is in danger.
Other sources of flexibility open to DSO	DSOs do not have access to other sources of flexibility / regulation, unless there is specific bilateral agreement between the DSO and flexibility/regulation provider.

DSOs are allowed to dispatch any generation units connected to the distribution network except for generation units with an installed capacity of 50MW or more connected to the so-called coordinated 110 kV network. The coordinated 110 kV network is a distribution network over which the TSO has a coordination role as far as planning and operational procedures are concerned.

In practice, according to the operational procedures described in distribution network codes, the DSOs do not dispatch any generation units connected to their grid unless (and only if) there is specific bilateral agreement between the DSO and generator. Also, in emergency situations i.e. when the safe operation of the grid is endangered the DSO may reduce/curtail the generation from any generation units.

DSOs do not have access to other sources of flexibility / regulation, such as batteries or capacitors, unless there is a specific bilateral agreement between the DSO and flexibility/regulation provider.

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 360: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSO is the main party responsible for meter rollout, although they are not bound by policy or law to meet specific meter rollout targets.
Monopoly services in the metering	DSOs are monopolists in metering activities.
Smart metering functionality	Main features and functionalities: • Quarter-of-an-hour measurement;

Issue	Approach adopted
	• Remote reading; • Remote disconnection and reconnection of customers; • Remote control of the maximum amount of power that a customer can withdraw; and • Local port to send real-time consumption information to local screens/computers.

DSOs´ own householders´ and small businesses´ meters; the meters of other consumer types are generally owned by the customers themselves. DSOs are monopolists in metering activities.

Industry and (almost all customers within) heavy industry are equipped with remote reading (smart) meters. The deployment of smart meters for householders is in its beginning stage, and is being driven by the DSOs. There is no formal policy or binding law related to the large-scale deployment of smart meters.

The main features of the smart meters already deployed (and planned to be deployed) include:

- Quarter-of-an-hour measurement;
- Remote reading;
- Remote disconnection and reconnection of customers;
- Remote control of the maximum amount of power that a customer can withdraw; and
- Local port to send real-time consumption information to local screens/computers.

In terms of the numbers of smart meters that are installed in Poland, the following information is available:

- In the group of the largest-scale customers, some 99% - 100% of customers have meters with remote reading capabilities in 4 of the 5 DSOs. For the remaining DSO, 50% of large-scale customers have meters with remote reading capabilities;
- For small business customers, of the 5 large-scale DSOs: around 100% of all customers served by 2 DSOs have smart meters; 50% of customers served by another 2 DSOs have smart meters; and 65% of customers served by the final DSO have smart meters;
- For ´institutional customers´ (that is, some small and medium sized enterprises), almost all customers (99,8% - 100%) of customers served by 4 of the 5 large DSOs in Poland have smart meters; 70% of such customers served by the other DSO have smart meters;
- In the small business and household customer group, around 2,5% of customers have a smart meter installed; this is around 420.000 customers.

The NRA understands that electricity consumption has fallen as a consequence of the meter installations, by around 1% - 4,5%. This result is based on an analysis that was undertaken on 100.000 meters / customers. During some time periods, the power reduction was as high as 10% to 30% of pre-smart meter consumption levels.

Country Report – Poland (gas distribution)

1. Overview of to the distribution sector

There are 35 DSOs in Poland, with the majority only serving limited geographic areas and a with small customer bases; there is one DSO with large geographic presence in the country.

DSOs are unbundled (legal and accounting).

Tariffs are proposed by each DSO and are approved (by the regulator) for a one-year period, and allowed revenues are determined for this period (also requires regulatory approval).

1.1. Institutional structure and responsibilities

In Poland there are 57 distributors supplying gas to 6.47 million customers covering an area of 180.122,7 km^2. The main DSO in Poland serves more than 90% of gas demand in the country. Summary data on industry structure is set out below.

Table 361: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Share of total demand
Poland	35	None	All DSOs with more than 100.000 customers	29	5,5%

In Poland there is one major DSO which is present through all regions of the country and which is composed of six (sub) DSOs (and which belongs to PGNiG capital group – the polish incumbent company). The tariff level of this DSO differs within the six regions of the country. In addition, there are 51 small DSOs, each of which has a small local presence in its respective area.

There is both legal and accounting unbundling of DSOs; DSOs belongs to the capital group of the trading company (no ownership unbundling). For DSOs with less than 100,000 customers, only accounting unbundling is effective.

The responsibility for setting distribution tariffs is held by the DSO; the tariff must be approved by the regulator before it can be implemented.

In relation to determining allowed revenues, Capital costs are subject to "cost reimbursement", while operating costs are subject to a "revenue cap" system. The tariffs to be used are calculated on the basis of the costs planned for the regulatory period. If the real costs differ from planned ones the DSO has the right to apply for the tariff correction. There is no automatic mechanism of balancing planned and real revenues from tariffs.

The assessment of allowed revenues takes into account assumptions of three outputs:

- energy delivered through the distribution network
- number of consumers connected
- capacity booked

The tariffs are approved (by the regulator) for a one-year period, and allowed revenues are determined for this period.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 362: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Proposes revenues to the NRA, through its proposal of tariffs	Proposes tariffs to the NRA	DSO responsible for making calculations of individual connections on case-specific basis
Government	Not involved	Not involved	Not involved
NRA	Takes decision on allowed revenues (for 1 year period) based on tariff proposal	Takes decision on tariff structure based on DSO proposal	Only involved if requested by a party which has been refused connection, and then the NRA has potential to reverse the decision

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process used for setting distribution tariffs involves the following steps. The tariffs to be used are calculated on the basis of the costs planned for the regulatory period. Planed, fixed and variable costs are identified; planned capacity bookings and volumes are defined (they are subject to the regulator's analysis – involving a comparison with historical data and a benchmarking exercise) and rates of fees are calculated.

Allowed revenues assessments take into account assumptions of three outputs:

- Energy delivered through the distribution network
- Number of consumers connected

- Capacity booked

If the real costs differ from planned ones the DSO has the right to apply for the tariff correction. There is no automatic mechanism of balancing planned and real revenues from tariffs.

The regulator is responsible for approving or not the DSO´s proposed distribution tariffs.

1.2. Key figures on revenue and tariffs

The total amount of allowed distribution revenues in Poland in 2013 was € 954 million. It is not known how this allowed revenue is split between the different customer types.

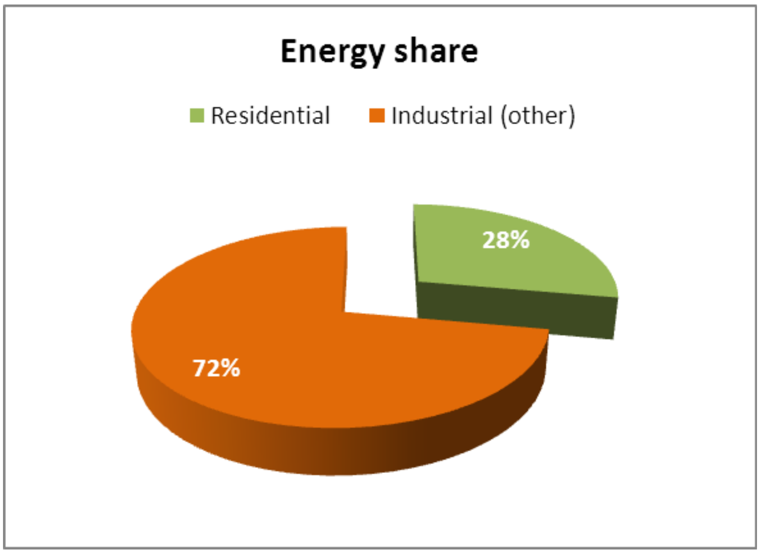
A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 363: Tariff components and customers per customer class

Customer classes	Tariff components	Number of customers
Residential	KWh, KW	6,274 million
Others (industrial)	KWh, KW	0,198 million
Total	-	6,472 million

The breakdown of energy volumes by customer category are set out in the chart below. Information on the allowed revenues by customer class is not available.

Figure 73: Proportion of energy and revenue accounted by customer categories



2. Regulation of distribution activities

Regulatory revenues are derived under a regulatory model which includes cost reimbursements for CAPEX and a revenue cap for OPEX. A 1-year regulatory regime is in place.

The role of the DISCO in Poland is to propose distribution grid tariffs, propose revenues per regulatory period, supply gas to end-consumers, and ensure connections to the distribution network are realised. The NRA has the role of reviewing and passing judgement on the adequacy of DSOs´ proposed revenues and tariffs. The Government develops sector-related legislation but not does play any direct role in the sector such as setting allowed revenue or tariffs.

The distribution sector is regulated under a mixed regulatory regime. Specifically, capital costs are subject to "cost reimbursement", while operating cost are subject to a "revenue cap" system. The regulatory period is for one year, it has no incentive-based elements.

The distribution tariff is itemized separately to end-users, and includes a fixed annual charge and an energy use component.

Key features of the regulatory regime are set out in the following table

Table 364: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Licensing regime - granted for the period not shorter than 10 years and no longer than 50 years
Duration of tariff setting regime	1 year
Form of determination (distributor propose/regulator decide)	The DSO proposes the tariffs and the proposed revenues for each (1 year) regulatory period, and the NRA has responsibility for approving them or not
Scope for appeal regulatory decision	Unspecified

2.2. Main incentive properties of the distribution regulatory model

The regulatory regime has no incentive-based elements.

At the same time a risk mitigation mechanism is in effect, specifically: tariffs are calculated on the basis of the costs planned for the regulatory period (one year). If the real costs differ from planned ones the company has the right to apply for the tariff correction. There is no automatic mechanism of balancing planned and real tariff's revenue.

No regulatory measures are implemented related to quality of service.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 365: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Cost reimbursement (CAPEX) and revenue cap (OPEX)
Capital expenditure	Total expenditure (no benchmarking)
Approach to operating expenditure	Total expenditure (no benchmarking)
Form of WACC applied	Reflective of actual structure of DSOs; WACC formula includes the following parameters: cost of equity, market risk premium, cost of debt, debt tax shield, and the corporate tax rate.

The following formula is applied in determining the WACC:

$$WACC = \frac{K_E}{1-t_e} \cdot \frac{E}{D+E} + K_D \frac{D}{D+E} \cdot \frac{(1-t)}{(1-t_e)}$$

Where:

- ✓ $K_E = r_f + \beta$ MRP is the cost of equity
- ✓ MRP is the Market Risk Premium
- ✓ K_D is the cost of debt
- ✓ t is the debt tax shield
- ✓ t_e is the corporate tax rate

3. Tariffs for distribution services

Tariffs are not geographically-uniform and are regulated for all customers.

Connection charges take the form of uniform applicable fees, depending on the capacity of the connection being developed. They cover both shallow and deep costs.

3.1. Distribution tariffs

The following approach is adopted to allocate distribution costs to the tariffs. Individual DSOs are responsible for setting tariffs which are then subject to approval from the regulator.

Planed, fixed and variable costs are identified; and planned capacity bookings and volumes are defined (they are subject to the regulator's analysis, including a comparison with historical data, and the rates of fees are calculated.

Consumers are divided into two categories:

- One category with an hourly capacity withdrawal not exceeding 110 kWh/h – four groups of customers varied due to yearly consumption (monthly fixed fee + variable fee), and
- One category with capacity booked exceeding 110 kWh/hr – six groups, based on their level of booked capacity (a capacity-related fee and a variable component).

Tariff components are not further split into sub-components. Tariff components are also not variable depending on time of use; and tariff components are linear within customer groups.

Tariffs are not geographically-uniform. Whilst there is one DSO with nationwide presence, the tariff applied by this entity varies between the six regions of the country. Furthermore, there are some 51 small independent DSOs (serving localised customer groups) which also have geographic variation in their tariffs.

Distribution losses are charged as a part of distribution tariffs: the energy-related component of the tariff includes the cost of losses.

Retail tariffs for end-users are regulated for all customers connected to the distribution network (which are not energy companies which purchase natural gas in order to resell the gas – this may occur if the retailer obtained individual exemption from the obligation to use regulated tariff). No special incentives are set, for large users such as gas power plants, within network tariffs. Social network tariffs are not in effect either.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 366: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included within the energy-related component of distribution tariffs.
Presence of uniform tariffs	No.
Presence of non-linear tariffs	No, tariffs are linear within customer groups.
Presence of regulated retail tariffs	Yes, tariffs are regulated for all customers connected to the distribution network.
Presence of social tariffs	No.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 367: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Deep
	Methodology adopted	Uniform fees depending on the connection capacity being developed
Hosting capacity	Scope to refuse connection	Yes, if the economic or technical conditions are not adequate
	Requirements to publish hosting capacity	No requirements on the DSO
	Targets and/or incentive schemes to enhance hosting capacity	None

For all consumers which are not energy companies (which have a connection to the pipelines with a pressure level not exceeding 0,5 MPa) there are uniform fees depending on connection capacity for connections (of up to 15 meters) and an additional fee for each meter over 15 meters. For connections to the high pressure network (over 0,5 MPa) the connection fee is individually calculated on the basis of ¼ cost. In contrast, energy companies pay 100% of their connection costs.

The connection fees (based on uniform rates as well as those calculated individually) cover shallow and deep costs.

A DSO can refuse connection for consumers or generators only in the event that economic or technical conditions for connections are not in place. In the case of a refusal of a connection, the regulator is notified and can be asked by the party seeking connection to reverse the DSO's decision.

There is no requirement on the DSO to publish, or notify the regulator of, the technical hosting capacity of the distribution network.

4. Distribution system development and operation

The DSO develops a distribution planning document, which is agreed on with the regulator through informal negotiations. Cost minimization is central within the plan.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 368: Approach to distribution planning

Issue	Approach
Form of distribution planning document	The distribution planning document is agreed with the regulator, not approved by formal decision. It is published on the DSO´s website.
- Key responsibilities for its development	The DSO develops the document, and the regulator is consulted and comments on it Adaptations are then made, and later it is published on the DSO´s website. It is not approved by formal decision.
- Relationship with quality of service targets	The plan should specify the anticipated scope of gaseous fuel supply, the projects aimed at the modernisation, expansion or construction of grids and possibly the new sources of gaseous fuels, and the projects which rationalise the use of fuels and energy by customers.
- How trade-offs between network development and alternative technologies are treated	Trade-offs are explicitly addressed in the development plan. The network plans shall be projects which rationalise the use of fuels; and projects in the field of acquisition, transmission and processing of measurement data from smart meters grid
- Requirements to integrate cost benefit analysis	No, the network plan only includes the decisions of the DSOs; there is no requirement to specify the CBAs.

According to the Polish Energy Law Act (art. 16 (1)) the DSOs and energy enterprises whose activity consists in the distribution of gaseous fuels shall prepare development plans for their respective areas of operation aimed at satisfying current and the future demand for gaseous fuels with consideration of the local land utilisation plan (or the development direction of the communities) as specified in the study of conditions and directions of the communities´ spatial planning.

The network plan should minimise the costs of investments and the costs borne by the energy enterprise so as to ensure that the expenses and costs associated with them do not cause any significant increase of prices and fee rates of gaseous fuels, whilst ensuring the continuity, reliability and quality of the supply.

DSOs hold full responsibility for metering, and own the meters. DSOs are monopolists in metering activities.

No decisions have yet been taken regarding the deployment of smart meters.

Some 48% of the natural gas delivered by DSOs is consumed by non-daily (or hourly) metered customers.

With regard to estimating non-daily metered consumption, metering data is collected periodically and is the basis (together with a temperature model) for consumption estimations for future periods.

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 369: Key approach to metering

Issue	Approach adopted
Discos role in metering	Full responsibility, and owners of the meters
Monopoly services in the metering	Monopolists in metering services
Smart metering functionality	No decisions on smart metering in effect to date.

Information on the rollout status of smart meters in the gas distribution sector in Poland has not been made available.

Country Report – Portugal (electricity distribution)

1. Overview of to the distribution sector

In Portugal the distribution activity is mainly controlled by the NRA which establishes the methodology to be used for calculating tariffs and prices and the ways of regulating the allowed revenues.

There are 13 DSO that operate in local regions of the country. DSO´s with more than 100000 customers are subject to legal unbundling according EU directives. Small DSO´s have only accounting unbundling.

1.1. Institutional structure and responsibilities

In Portugal there are 11 DSO supplying electricity to above 6,086 million of connected customers covering the whole country. Total energy consumption in 2013 amounted to 41,8 TWh at distribution level. If the islands of Azores and Madeira are considered, 2 more DSO must be added (making a total of 13) and the consumption is 45,4 TWh while the customer number raises to 6,344 million.

DSO´s with more than of 100000 customers are legally unbundled from transmission, generation, supply and other activities in accordance with the rules of unbundling laid down in the Article 26 of Directive 2009/72/EC. However in the case of Portuguese islands (Madeira and Azores), the EU directives are derogated and only separation of accounts is enforced for regulation purposes.

For DSO´s with less than 100000 customers, there is only accounting unbundling. Regulated accounts are audited by external entities.

Summary data on industry structure is set out below.

Table 370: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Share of total demand
Portugal	13		3	10	The 13 DSO in the country account for 95.2% of total demand. The rest is consumption connected to the transmission network.

The responsibility for setting distribution tariffs and allowed revenues is spread between the following jurisdictions:

- **The NRA,** Entidade Reguladora dos Serviços Energéticos (ERSE) is the main responsible for the calculation of allowed revenues and setting the tariffs for electricity distribution. The NRA defines and applies the methodology and sends proposal to the Tariff board that includes the allowed revenues of regulated activities, tariff structure, prices, etc.
- **Tariff Board,** Stakeholders including regulated companies, members of consumer associations and institution entities. The NRA receives the opinion of the Tariff board before taking its own decision.
- **The Ministry/Government** issues principles in the primary law. Imposes legal obligations to the DSO that could impact in the allowed revenues (Electricity law DL 215A/2013)

The breakdown of responsibilities in relation to tariff setting is summarized in the table below.

Table 371: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO			
Tariff board[1]	Also involved	Also involved	Also involved
Government	Defines main principles	Defines main principles	Defines main principles
NRA	X	X	X

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

[1]The Tariff Board is where the regulated companies of the electricity sector and consumers' associations are represented, to discuss regulation issues and the regulator's proposals, including codes and tariffs.

[2] Government approved the statutes of the regulator and the gas sector law where the main tariff principals are set. These are general principals and do not prescribe how to calculate tariffs in detail

1.2. Key figures on revenue and tariffs

In the distribution activity the allowed revenues in Portugal were € 1,279 billion for 2013. The distribution costs are not treated separately.

In Portugal, distribution tariffs are defined by voltage levels:

- High Voltage (HV). Voltage level more than 45kV, but equal or less than 110 kV. Typical large industrial consumers.
- Medium Voltage (MV). Voltage level more than 1KV but equal or less than 45kV. Typical small industrial consumers.
- Low Voltage (LV). Voltage level equal or less than 1kV. There are two subcategories:
    - o Special Low voltage (SpLV) with contracted power higher than 41,4kW. Typical small business consumers

- Standard Low voltage (StLV) with contracted power equal or lower than 41,4kVA. Typical household consumers.

Portuguese distribution tariff has the following components:

- Capacity charge.
  - Contracted power for HV, MV, and SpLV and StLV. Corresponds to the maximum average active power in kW, in any uninterrupted period of 15 minutes, during the last 12 months. For StLV corresponds to the apparent power in kVA. (eur/KW.Month)
  - Average peak power for HV, MV and SpLV. Corresponds to the ratio between peak hour active energy and the number of peak hours. (eur/KW.Month)

- Energy Charge. Active energy, differentiated by time period and seasonal period. (Eur/kWh)
  - For HV, MV and SpLV, there are 4 period of active energy (Peak hours, Half-Peak hours, Off-Peak hours and Super Off peak-Hours) in 2 seasonal periods for HV and MV (Season I-IV and Season II-III) and no seasonal period differentiation for SpLV.
  - For StLV, there are 3 tariff options for energy charge, with no seasonal period differentiation:
    - One-period tariff. No time-of-use differentiation.
    - Two-period Tariff. There are two time period differentiation.
    - Three-period tariff. There are three time period differentiation.

- Reactive charge. Reactive energy component which applies to HV and MV voltage levels and also to SpLV. Reactive energy is only billed to the consumer regarding the network and voltage level of connection. (Eur/kvarh)
  - The Inductive Reactive Energy Supplied that is the reactive energy supplied which exceeds 30% of the active energy, in peak and half-peak hours.
  - The Capacitive Reactive Energy Received that is the reactive energy received in off-peak hours.

A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below. The revenues presented refer only to distribution tariff or distribution costs and not to the whole third-party access tariff (TPA tariff). Customers pay the TPA tariff which includes also transmission network costs and global use of the system tariff components. Moreover, the revenues are calculated for the mainland incumbent DSO only.

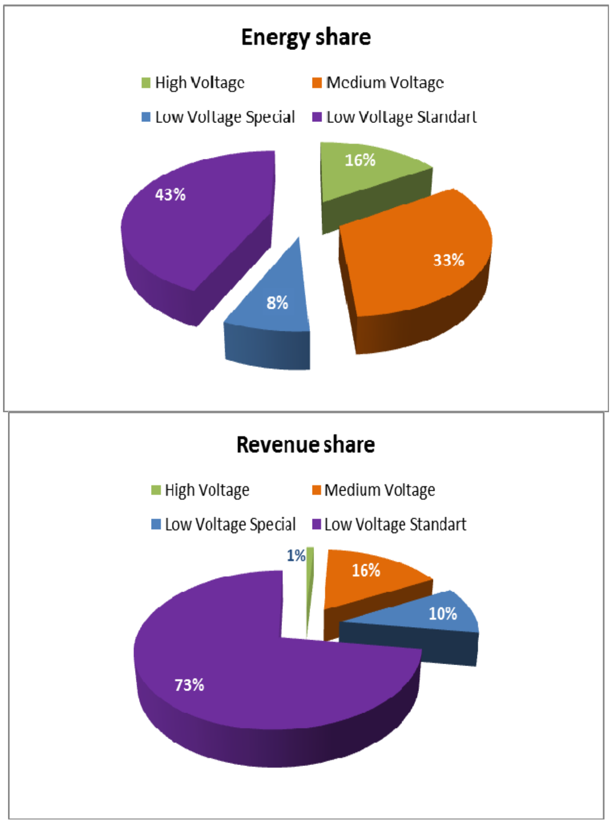
Table 372: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenue (€ million)
High Voltage	Contracted power, Peak hours power, Active energy charge (4 time periods-4 seasons), Inductive Reactive energy charge,	280	17

Customer classes	Tariff components	Number of customers	Revenue (€ million)
	Capacitive Reactive energy charge		
Medium Voltage	Contracted power, Peak hours power, Active energy charge (4 time periods-4 seasons), Inductive Reactive energy charge, Capacitive Reactive energy charge	23538	210
Low voltage - Special	Contracted power, Peak hours power, Energy charge (4 time periods), Inductive Reactive energy charge, Capacitive Reactive energy charge.	33512	130
Low voltage - Standard	Contracted power, Energy charge (1 time period, 2 time period and 3 time period)	6028186	922
Total	-	**6085516**	**1279**

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 74: Proportion of energy and revenue accounted by customer categories



The figure above shows that in 2013, Low Voltage Standards group (Typical Household consumers) have paid on average 73% of distribution costs and they have consumed only the 43% of active energy.

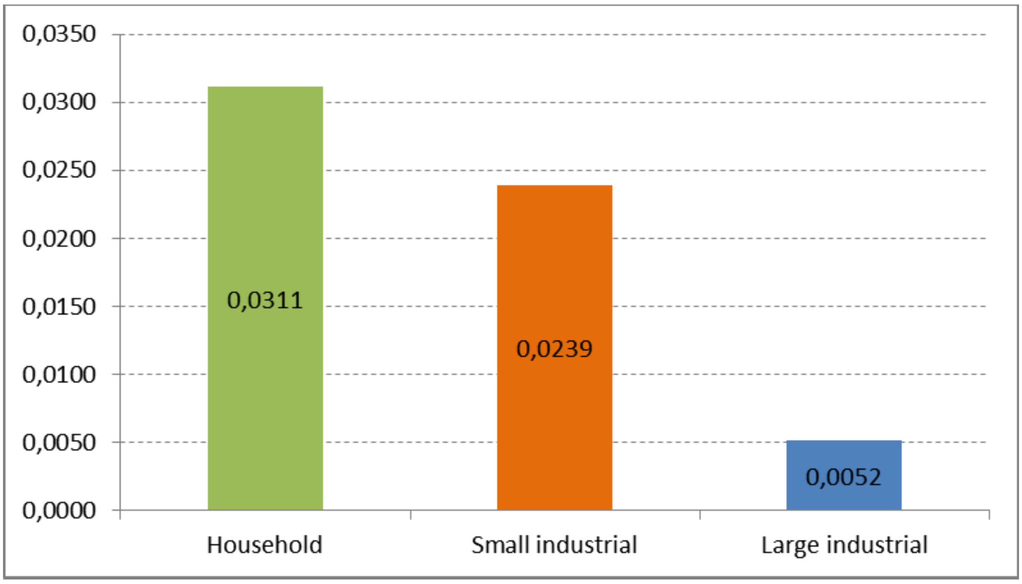
The typical distribution network tariff in 2013 for Households, Small industrial and Large industrial customers is illustrated below. Note that the average cost given in the table refers only to distribution tariff or distribution costs and not to the whole third-party access tariff (TPA tariff). Customers pay the TPA tariff which includes also transmission network costs and global use of the system tariff components.

Table 373: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Power charge	Average Peak hours charge	Distributed Energy charge	Reactive energy	Total
Household	3500 kWh	41 €		68 €		109 €
Industrial consumer	50MWh	255 €	690 €	160 €	91 €	1196 €
Industrial consumer with an 7.000 use hours	24000 MWh	10739 €	77858 €	21022 €	14340 €	123959 €

The resulting average tariffs per kWh are illustrated below.

Figure 75: Average network charges (€/kWh), 2013



2. Regulation of distribution activities

The regulatory model of the distribution electricity sector is a mix of two. Capital costs are subject to "cost reimbursement" while operating cost are subject to an "incentive based" mechanism for controllable costs. DSO operates in a concession regimen.

Allowed revenues are defined annually. CAPEX is assessed every year and OPEX is defined in the first year of regulatory period and updated both with RPI-X and the evolution of the cost drivers set. The tariffs are updated accordingly.

2.1. General overview

The Decree-Law 29/2006, amended by Decree-Law 215-A/2012, provides the main rules for the electric Portuguese system, including distribution activities. The law establishes the main role of DSO. According to article 39, the DSO´s shall: "Provide to interested parties, without discrimination, access to distributions networks, based on tariffs applicable to all customers in terms of the Access to Networks and Interconnections Code."

The NRA (ERSE) is the administrative authority for regulating the energy sector and has a range of powers and responsibilities defined by law. "The mission of ERSE is to regulate the electricity and natural gas sectors, being an effective tool for the efficient and sustainable operation of the respective markets while ensuring the protection of consumers and the environment, transparently and impartially". The NRA scope is focus "… protecting consumers' rights and interests as regards prices, services and service quality; monitoring compliance with public service obligations and all other legal, regulatory and similar requirements; guaranteeing economic and financial balance to the activities of the regulated sectors exercised in the public interest companies within the framework of appropriate and efficient management; promoting competition in the energy markets between all their players".

The distribution activities are regulated under a public concession regime, with a specific regimen for HV and MV distribution networks and other for LV distribution networks.

The HV and MV electricity distribution are subject to a public concession between the Government and the DSO lasting 35 years. The LV electricity distribution is also subject to a public concession between the DSO and the municipalities. However, DSO and municipalities signed contract (like sub-concessions), whereat the DSO´s are responsible for the operation, maintenance and investment in the LV electricity distribution for 20 years. Some of these concessions are facing their end in the coming years.

The broad regulatory model implemented in Portugal is a mix of "cost reimbursement" and "incentive based". Capital costs are subject to "cost reimbursement", while operating cost are subject to an "incentive based" regulation for controllable costs.

Key features of the regulatory regime are set out in the following table

Table 374: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession. HV-MV networks, maximum 35 years period LV networks, maximum 20 years period
Duration of tariff setting regime	3 years
Form of determination (distributor propose/regulator decide)	Regulator decides
Scope for appeal regulatory decision	No, except for the hearing of the Tariff Board that issues an Opinion on the tariff proposal

2.2. Main incentive properties of the distribution regulatory model

The NRA defines the annual allowed revenues for the regulatory period. Operating expenditures (OPEX) are defined in the first year of regulatory period and updated annually with RPI and X factor. The definition of x factor is based on benchmarking studies through the application of non-parametric methods and the analysis of performance with comparison to efficiency targets. Capital cost (CAPEX) and investments are assessed each year. The tariffs are updated accordingly.

The OPEX that are included on the allowed revenues of distribution activity are based on assumptions of the following outputs:

- Energy delivered through the distribution network
- Average annual number of consumers connected to the distribution network
- Quality of service
- Level of losses

About the CAPEX, in the allowed revenues the NRA accepts all the investments paid by DSO that are included in the RAB. The asset base considers the book value of assets. Costs with metering devices are not accepted in the RAB according to the Portuguese Law (Metering activities are not recognized for remuneration of DSO activities).

The following key regulatory incentives apply for the DSOs:

- Incentive to reduce operating cost. There is an X factor to update the OPEX, however innovative Investments have a remuneration premium and the x factor in OPEX is increased so that the gain to the company is also a gain to consumers
- The concession fees and the cost with restructuring plans of human resources are accepted outside the price cap methodology

At the same time the following tools are provided to mitigate risks:

- Regulatory system does not place the volume risk only on the DSO. Energy delivered through the distribution network is one of the drivers included in the price cap mechanism. By this way the risk of energy fluctuations is partially shared between the DSO and consumers.

Until 2012, the role of NRA in quality of electricity distribution was focus on the supervision of compliance with the quality of service code. In 2013, the NRA published a new quality of electricity code with guaranteed standards (technical and commercial). Allowed revenues are calculated two years later based on real values and increased (or decreased) if the DSO performs better (or worse) than some predefined quality targets.

Automatic compensations are granted to consumers in case some guaranteed quality standards are not met. Costs of those compensations are not included in the allowed revenues of the DSOs. DSO can charge customers for a compensation in case of absence of the customer during appointments to visit customers' premises and in case of failure on clients' premises wiring for which customers are responsible.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 375: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Capital costs are subject to "cost reimbursement", while operating cost are calculated in year one of the regulatory period and subject to an "incentive based" X factor system.
Regulatory asset base	In the asset base is considered the book value of assets. Costs with metering devices are not accepted in RAB (Portuguese law).
Capital expenditure	In order to assess the DSO's investment requirements an ex-ante analysis is performed on several indicators (quality of service, operational efficiency, network efficiency and security of supply). Furthermore the regulator supervises the schedule, the budget and the execution of the investment projects assessing their impact on the above mentioned indicators. The selection of the project investments is made by the DSO according to a Cost-Benefit analysis. No ex-post assessment of "usefulness" is carried out. All the investments paid by DSO are included in the RAB (Costs with metering devices are not accepted in RAB) and therefore accepted in the allowed revenues.
Approach to operating expenditure	The definition of x factor is based on benchmarking studies through the application of non-parametric methods and the analysis of performance with comparison to efficiency targets.
Form of WACC applied	Nominal, pre-tax WACC
Additional revenue items (where applicable)	The adjustment between the allowed revenues (based on estimated information) and actual revenues (recalculated with real information) are included in the allowed revenue two years later corrected by a financial compensation.

The following formula is applied in determining the weight average cost of capital WACC:

$$WACC = \frac{R_E}{1-T} \cdot \frac{E}{D+E} + R_D \frac{D}{D+E} \cdot$$

Where:

- R_D: is the cost of debt. Calculated according to the next formula:

$$R_D = R_F + RP_D$$

- R_F: is the risk free rate (10 year yields for countries with AAA rating. Average over a 5 years period).
- RP_D: is the debt risk premium (Default spread for the theoretical optimal gearing value).
- The debt leverage (Ratio E/D) is set at target considered as theoretical optimal value by the regulator. (50%)
- R_E: is the real price of equity and own funds calculated according to the formula:

$$R_D = R_F + \beta_E RP_M$$

- RP_M: is the market risk premium shows investor risk as the difference between the yield of a country's market portfolio and the risk-free rate of return. The value is bases on benchmarking and market analysis.
- β_E is weighted ratio β, which defines the sensitivity of a company share to the market risk, taking into account the income tax rate and the debt share, calculated according to the formula:

$$\beta_L = \beta_A \times \left[1 + (1 - T) \times \frac{D}{E}\right]$$

- B_A. Bottom-up Betas based on benchmarking of similar companies and market analysis
- T is the effective tax rate. (National level in the beginning of the regulatory period)

3. Tariffs for distribution services

3.1. Distribution tariffs

The regulator is in charge of setting the distribution tariffs (based on allowed revenues). Contracted power, average peak power, active energy, differentiated by time period and seasonal period, and reactive energy are the price variables. Together they allow to pass on to consumers the multiplicity of factors that affect the costs of distribution networks.

There are three distribution network tariffs according to the voltage level. For each distribution network (HV, MV and LV) the prices of capacity charges (contracted power and average power in peak hours) are calculated through the long run average incremental costs methodology.

The costs of the network sections closer to the delivery points are recovered by the contracted power price, measured on short periods of time, as 15 minutes, because the design of the peripheral sections is conditioned by the behaviour of a small number of consumers (in some cases , only one consumer). The costs of the more central network sections are recovered by the prices of average power in the periods of higher demand. In fact, the most central network sections are used by a large number of clients and, due to reduced synchronization of the peak occurrences of 15 minutes of each consumer (annually or monthly), we may consider that the individual behaviour of a consumer only affects the design of these more central sections of the network in proportion to its average peak power on a wider period of time, coincident with the network aggregated peak and not through its annual peak power, or even monthly. For these reasons, the power measured in a more wide period of time, coincident with the time periods where the network peak powers are observed, is a variable more adequate than the annual peak power of each consumer to transmit to consumers the costs associated with the more central sections of the distribution network, as well as the costs of the upstream networks imputable to each voltage level.

The active energy delivered on each time period causes losses on distribution networks, different in size and cost for each time period. Hence some investments are needed because of losses. Technical losses depend on a set of factors, namely on the type of network, underground or aerial, and on power, once losses are proportional to the square of power. Being aware that losses, and its economic value, vary considerably with the time and seasonal period of consumption, the adequate billing variables to give consumers the adequate economic signal of the cost of losses are active energy, by time period and seasonal period.

The reactive energy supplied (inductive demand) is a variable which should be used on the billing of the network use on peak and half-peak time periods, because its compensation allows the reduction of the electric system global costs, either on the minimization of energy losses on the peripheral network sections, or on its reinforcement.

Concerning reactive energy received (capacitive demand), its compensation may also be desirable in off-peak periods, because it may lead to overvoltage situations on the delivery points.

The details of distribution tariff by voltage class and their components are summarized in section 1.2 Key figures on revenue and tariffs.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 376: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Losses are covered by requiring each entity responsible for balance to deliver more power than the one consumed by its loads.
Presence of uniform tariffs	The same tariff for consumers everywhere in the country. No tariff differentiation according to DSO.
Presence of non-linear tariffs	No, all tariff components are linear. Energy component is differentiated by time period (peak, half-peak, off-peak and super off-peak times) and seasonal period.
Presence of regulated retail tariffs	End-user regulated tariffs published by ERSE for all customers ceased to exist on the 1st of July 2013. Until the end of 2015, consumers who have not chosen a supplier from the market are subject to the application of transitory tariffs, which may be revised quarterly by ERSE and subject to an incentive to encourage the transition of customers from the regulated market to the liberalized market. .
Presence of social tariffs	Social network tariffs are implemented. A discount is given on the price of contracted power. Producers pay the burden.

Generators connected to the distribution network do not pay distribution tariffs, they only pay generator specific transmission tariffs. There are not special incentives in network tariffs for large users like power plants.

The distribution tariffs are published at (*only available in Portuguese*):
http://www.erse.pt/pt/electricidade/tarifaseprecos/2014/Documents/Diretiva%2025-2013.pdf

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 377: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Connection charges are deep for consumers and generators.
	Methodology adopted to determine connection costs	Generators: Connection costs are calculated case by case and paid by the generators. Large consumers (S>=2 MVA): Connection costs are computed case by case and distributed between the DSO and the consumers on an agreement basis. To determine the connection cost in Generator and Large consumers, DSO makes an estimate but the

	Issue	Approach
		client can ask the regulator to set the price in case he does not agree with the DSO's estimate. Small consumers (S<2MVA): Part of the cost is supported by the consumer and the other by the DSO taking into account the length of the connection, the demanded power and the use of the connection (exclusive and/or shared). There are a standard connection costs approved by the regulator.
Hosting capacity	Scope to refuse connection	DSO must accept all the connection requests once verified the technical and legal conditions.
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	There are no incentive schemes to enhance hosting capacity. DSO is assumed to have a duty to connect all the requested capacity.

4. Distribution system development and operation

In Portugal, according to the national legislation, the distribution system development plan is submitted every two years to the regulator which held a public consultation. After collecting the responses, the regulator issues a reasoned opinion, proposing all modifications considered relevant to the minister responsible for the energy sector, which approves the plan.

DSOs have full responsibility for metering and own the meters.

There are some massive smart meters pilot projects in Portugal. A review of cost-benefit analyses is expected in 2014.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 378: Approach to distribution planning

Issue	Approach
- Form of distribution planning document	According to the national legislation, the distribution system development plan is submitted every two years to the regulator which held a public consultation. The last investment plan proposed by the DSO for the period 2015-2019, similarly to what happened to the TSO's one, was released by the

Issue	Approach
	regulator to public consultation After collecting the responses, the regulator issues a reasoned opinion, proposing all modifications considered relevant to the minister responsible for the energy sector, which approves the plan. The plan time horizon is 5 years and the voltage levels concerned are Medium Voltage and High Voltage. The distribution network plan considers 4 main vectors of interest: Quality of service, network efficiency, operational efficiency and security of supply
- Key responsibilities for its development	Once approved (see previous answer), the DSO´s are responsible for implementing their network development plans, and the regulator supervises the schedule, the budget and the execution of the investments projects.
- Degree of integration with renewables plan	Renewable generation targets are set by the Government at national level. These targets are converted into planned facilities/connections by promoters and are explicitly taken as an input in the distribution development plan.
- Relationship with consumption trends	The evolution of consumption in the distribution area is explicitly considered in the development plan based on a security of supply monitoring annual report defined by the legislation.
- Relationship with quality of service targets	Quality of service targets are explicitly taken as an input in the distribution development plan which quantifies the investments related to the quality objectives in the distribution area.
- How trade-offs between network development and alternative technologies are treated	The distribution network development plan reports the decisions of the DSO and the corresponding operational savings, divided by project. The analysis on which those decisions are based are not public.
- Requirements to integrate cost benefit analysis	No. The network development plan reports only the select investment projects selected by the DSO. The analysis on which those decisions are based are not public.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 379: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	DSO´s do not has any control on embedded generators. DSO is responsible for the security of their system. In case of network constraints the DSO may be forced to require generators to disconnect.
Possibility to dispatch flexible loads	No. Flexible loads are controlled by the

Issue	Approach
	Transmission System Operator
Other sources of flexibility open to DSO	The sources of flexibility that DSOs have access to are capacitor banks and transformer taps for voltage control. Additionally, in coordination with the measures of the transmission system operator to control the system frequency, the DSO has also relays of automatic load shedding.

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 380: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs have full responsibility for metering and own the meters.
Monopoly services in the metering	Yes
Smart metering functionality	The main features of the smart meters will be: • Quarter of an hour measurement, but only in case the customers do agree to this • Remote reading • Remote disconnection/reconnection of customers • Remote control of the maximum power that can be withdrawn • Local port to send real time consumption, but only in case the customers do agree to this information to a local screens or computers

The first economic evaluation of long-term costs and benefits associated with the smart metering roll-out has been completed in 2012, but a review is expected during 2014.

Portugal continues with the deployment of large-scale smart metering pilot projects. Among these, the InovGrid project is covering to date 31000 Low Voltage customers equipped with smart meters. The integrated and intelligent electricity system that started in the municipality of Évora, will be developed in another seven regions in Portugal with the additional installation of 100000 smart meters.

Country Report – Portugal (Gas distribution)

1. Overview of to the distribution sector

In Portugal, there are 11 DSO that operate in delimited regions. DSO´s with more than 100000 customers are legal unbundled according EU directives. Small DSO´s have only unbundling of accounts.

Distribution activity is regulated by ERSE which sets and approves the regulatory methodology according to the general principles of the law.

1.1. Institutional structure and responsibilities

In Portugal there are 11 DSO´s which operate with regional scope. The DSO´s are delivering gas to 1,341 million of customers. Total energy consumption equivalent in 2013 was 25,152 TWh. There are also 11 Last Resort Suppliers, which belong to the same company groups of the DSOs and operate in the same geography.

Generally, all DSO are legally unbundled from storage, regasification, transmission, supply and other activities in accordance with the rules of unbundling laid down in the Article 26 of Directive 2009/72/EC. Consequently DSO´s with more than 100,000 customers are legally unbundled from the last report supplier.

For DSO´s with less than 100000 customers, there is only accounting unbundling from the last resort supply activity. Regulated accounts are audited by external entities. In these cases, the DSO´s are also the regulated last resort suppliers.

Summary data on industry structure is set out below.

Table 381: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Share of total demand
Portugal	11		4	7	Total consumption delivered at distribution level represents 47% of total consumption, which includes also consumers connected at transmission level

The responsibility for setting distribution tariffs and allowed revenues is spread between the following jurisdictions:

- **The NRA,** Entidade Reguladora dos Serviços Energéticos (ERSE) is responsible for the calculation of allowed revenues and for setting the tariffs for gas distribution. The NRA defines and applies the methodology and sends proposal to the Tariff board that includes the allowed revenues of regulated activities, tariff structure, prices, etc.
- **Tariff Board,** Stakeholders including regulated companies, members of consumer associations and Government entities. The NRA receives the opinion of the Tariff Board before taking its own decision.
- **The Ministry/Government** issues principles in the primary law. Imposed legal obligations to the DSO that could impact in the allowed revenues.

The breakdown of responsibilities relating to tariff setting is summarized in the table below.

Table 382: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO			
Tariff Board[1]	Also involved	Also involved	Also involved
Government[2]	Defines main principles	Defines main principles	Defines main principles
NRA	X	X	X

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

[1]The Tariff Board is where the regulated companies of the natural gas sector and consumers' associations are represented, to discuss regulation issues and the regulator's proposals, including codes and tariffs.

[2] Government approved the statutes of the regulator and the gas sector law where the main tariff principals are set. These are general principals and do not prescribe how to calculate tariffs in detail.

1.2. Key figures on revenue and tariffs

In the distribution activity the allowed revenues in Portugal were € 302 million from July/2012 to June/2013 (Period called "gas year"). For the period from July/2013 to June 2014, the allowed revenues were € 309 million.

The distribution costs are not treated separately between metering, distribution and commercial service.

In Portugal there are three distribution tariff groups, defined according to pressure level and annual consumption:

- Medium pressure (relative pressure: 1 bar < p < 20 bar)
- Low pressure and annual consumption above 10000 m^3

- Low pressure and annual consumption under 10000 m^3

For medium pressure and Low pressure for consumers with annual consumption >10000 m3, there are four tariff options:

- Long utilization:
  - The capacity term is paid for a 12 months period and considers the maximum used capacity in the last 12 months.
- Short utilization:
  - The capacity term is paid for a 12 months period and considers the maximum used capacity in the last 12 months.
  - The short utilization used capacity price is lower than the long utilization used capacity price, due to a transfer to the energy price component, which is higher in this option, comparing to the long utilization energy price.
- Flexible:
  - Flexible monthly (exclusively monthly):
- There is no annual base capacity booking.
- The monthly capacity equals the corresponding month maximum used capacity.
- In the summer (April to September) the monthly capacity price is equal to the used capacity price of the long utilization tariff option.
- In the winter (October to March) the monthly capacity price is 2x the used capacity price of the long utilization tariff option.
  - Combined booking of annual base capacity and additional monthly capacity (exclusively in the summer months):

    The annual base capacity must equal the maximum capacity in the winter months (October to March) of the last 12 months.
    The additional monthly capacity in the summer months (April to September) is the difference between the maximum used capacity in that month and the annual base capacity.
    The annual base capacity price is equal to the used capacity price of the long utilization tariff option.
    The additional monthly capacity price in the summer months (April to September) is equal to the used capacity price of the long utilization tariff option.

Distribution tariffs for medium pressure and Low pressure >10000 m^3 include the following components:

- Fixed term, in Euros per month
- Energy term, in Euros per kWh. Time period differentiation (Peak and off peak)
- Used capacity term, in Euros per kWh/day per month. The used capacity term of the monthly flexible distribution tariff is differenced per two year seasons.

For Low pressure and annual consumption <10000 m^3, there are also four tariff subgroups according to energy consumption:

- Scale 1. Annual consumption less than 220 m^3
- Scale 2. Annual consumption between 221 m^3 and 500 m^3
- Scale 3. Annual consumption between 501 m^3 and 1000 m^3
- Scale 4. Annual consumption between 1001 m^3 and 10000 m^3

Distribution tariffs for Low pressure < 10000 m^3 include the following components:

- Fixed term, in Euros per month
- Energy term, in Euros per kWh. No time differentiation.

The current prices of distribution tariffs, in gas year 2013-2014, are presented in annexes.

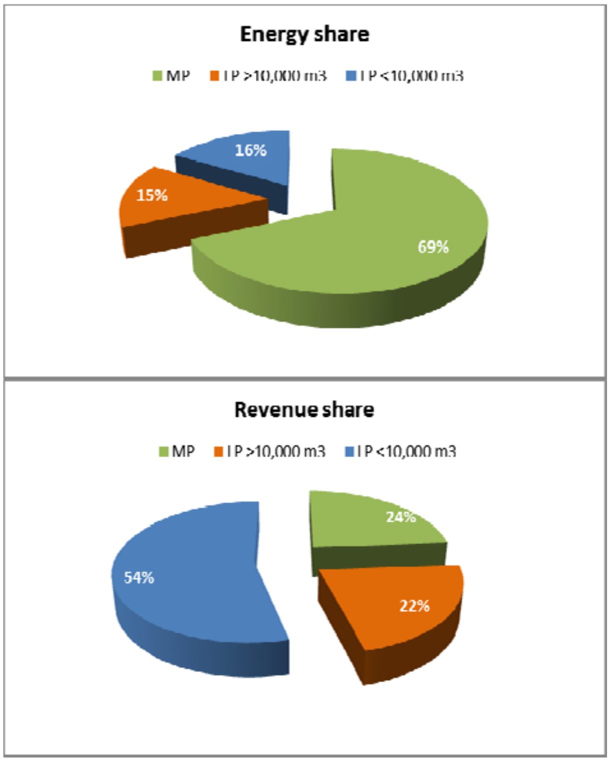
A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below. The revenues presented in the table refer only to distribution tariff or distribution costs and not to the whole third-party access tariff (TPA tariff).

Table 383: Tariff components, customers and revenues per customer class 2013-2014.

Customer classes	Tariff components	Number of customers	Revenue (€ million)
Medium pressure (MP)	Fixed term, Energy term and Used capacity term	399	72,772
Low pressure (LP) higher than 10 000 m^3	Fixed term, Energy term and Used capacity term	4061	69,073
Low pressure (LP) less than 10 000 m^3	Fixed term and Energy term	1336577	167,098
Total	-	**1341037**	**308,943**

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 76: Proportion of energy and revenue accounted by customer categories



The figure above shows that in 2013, Low pressure group with annual consumption of less than 10,000 m3 (Typical Household consumers) has paid on average 54% of distribution costs and has consumed only the 16% of gas. In the other hand, medium pressure group (typical large industrial consumers) has paid on only 24% of the distribution costs and has consumed 69% of the energy.

The typical network tariff in 2013 for Households, Small industrial and large industrial customers is illustrated below. Note that the average cost given in the table refers only to distribution tariff or distribution costs and not to the whole third-party access tariff (TPA tariff). Customers pay the TPA tariff which includes also transmission network costs and global use of the system tariff components.

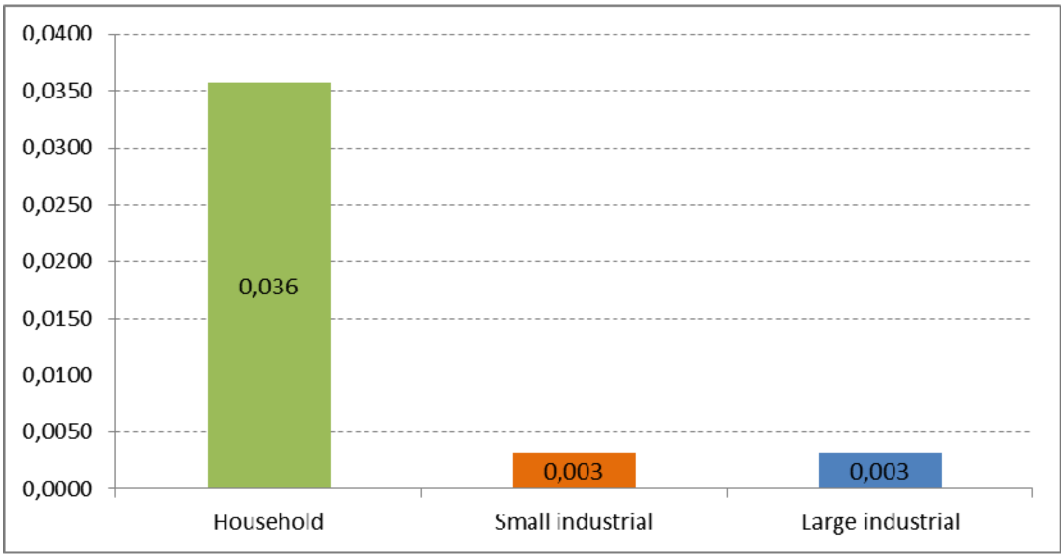
Table 384: Breakdown of annual charges – typical customer types, 2013-2014 (€)

Customer type	Notional Energy usage	Fixed term	Energy term	Used capacity term	Total
Households with annual consumption of 15,000 kWh	15,000 kWh (Household consumption in Portugal is below this value)	29€ (2,43€/ month)	507 € (0,03376014 €/kWh)		536€
Industrial Consumer with an annual consumption 50,000 MWh and 7,000 use	50,000 MWh	5116 € (426,29 €/mont	35748 € (0,00071495 €/kWh)	118557 € (0,057632 EUR/(kWh/day)/month)	159421 €

Customer type	Notional Energy usage	Fixed term	Energy term	Used capacity term	Total
hours		h)			
Industrial Consumer with an annual consumption 90,000 MWh and 7,000 use hours	90,000 MWh	5116 € (426,29 €/month)	64346 € (0,00071495 €/kWh)	213403 € (0,057632 EUR/(kWh/day)/month)	282865 €

The resulting average tariffs per kWh are illustrated below.

Figure 77: Average network charges (€/kWh), 2013-2014



2. Regulation of distribution activities

The NRA is responsible of define, approve and publish the Tariff Code. This code is presented to public consultation and to the Tariff Board for an opinion. Ultimately, the NRA approves and publishes the code.

The regulatory model of the distribution natural gas sector is a mix of two. Capital costs are subject to “cost reimbursement” while operating cost are subject to an “incentive based” mechanism for controllable costs. The regulatory period is three years long.

There are DSO operating in a concession regime and another under licence regime.

2.1. General overview

Thedecree-law nr. 30/2006, amended by decree-law 230/2012, provides the main rules of the Portuguese natural gas system, including distribution activities. The law establishes the main role of DSO. According to article 34, the DSO´s shall: “Provide to interested parties, without discrimination, access to distributions networks, based on tariffs applicable to all customers in terms of the Access to Networks, Infrastructures and Interconnections Code.”

The NRA (ERSE) is the administrative authority responsible for regulating the energy sector and has a range of powers and responsibilities defined by the law. “The mission of ERSE is to regulate the electricity and natural gas sectors, being an effective tool for the efficient and sustainable operation of the respective markets while ensuring the protection of consumers and the environment, transparently and impartially”. The NRA scope is focus “… protecting consumers’ rights and interests as regards prices, services and service quality; monitoring compliance with public service obligations and all other legal, regulatory and similar requirements; guaranteeing economic and financial balance to the activities of the regulated sectors exercised in the public interest companies within the framework of appropriate and efficient management; promoting competition in the energy markets between all their players”.

In Portugal, there are licence and concession regimes. Five of the eleven DSO´s are subject to a concession regime for a period of 40 years and other 6 DSO´s are subject to a license regime for a period of 20 years.

The NRA is responsible for publishing the Tariff Code, which includes matters such as calculation of allowed revenues, tariff design, tariff setting methodologies and information requirements. This Tariff Code is submitted to public consultation and is subject to an opinion from the Tariffs Board prior to its approval.

The public consultation procedure for tariff setting is defined in the Regulator’s statutes and in the Tariff Code. By April 15 of every year, the NRA issues a proposal, along with justification documents, to the Tariff Board. This board replies with an Opinion by May 15. The NRA acknowledges the opinion and issues a final decision which publishes in its own webpage and on the Official Journal, by June 15.

Regulated tariffs are calculated for the period of one year going from July to June. The allowed revenues are set on calendar year basis. The regulatory period is three years long.

Key features of the regulatory regime are set out in the following table

Table 385: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession, maximum 40 years period License, maximum 20 years period The assets are property of the Portuguese Government as concession grantor.
Duration of tariff setting regime	3 years
Form of determination (distributor propose/regulator decide)	Regulator decides Tariff board could propose and give their opinion. This board includes DSO ´s representatives and other stakeholders.
Scope for appeal regulatory decision	No

2.2. Main incentive properties of the distribution regulatory model

The broad regulatory model implement in Portugal is a mix of "cost reimbursement" and "incentive based". Capital costs are subject to "cost reimbursement", while operating cost are subject to an "incentive based" for controllable costs.

The following key regulatory incentives apply for the DSOs:

- Price cap regulation for OPEX. OPEX cost base is fixed in the beginning of regulatory period (every 3 years) and updated annually with RPI -X factor and evolution of the cost driver set. The definition of x factor is based on benchmarking studies through the application of non-parametric methods and the analysis of performance with comparison to efficiency targets. The tariffs are updated accordingly. Different X factors in the price cap formula are set for different DSO, regarding the performance and the maturity of each DSO.
- Rate of return regulation for CAPEX, on annual basis and with adjustments by real values ex post. Each DSO for year t-2 is adjusted ex post in year t based on real values. The difference between forecasted revenues and real revenues of year t-2 are included on allowed revenues of year t added by a financial compensation.

The OPEX that are included in the allowed revenue of distribution activity are based on assumptions of the following outputs:

- Energy delivered through the distribution network
- Average annual number of consumers connected to the distribution network

In the other hand, CAPEX included on the allowed revenues are assessed every year.

At the same time the following tools are provided to mitigate risks:

- Regulatory system does not place the volume risk only on the DSO. Energy delivered through the distribution network is one of the drivers included in the price cap mechanism. By this way the risk of energy fluctuations is partially shared between the DSO and consumers.

There is no regulatory incentive on quality of supply. Automatic compensations are granted to consumers in case some guaranteed quality standards are not met. These compensations costs are not included in the allowed revenues of the DSO´s.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 386: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Capital costs are subject to "cost reimbursement", while operating cost are calculated in year one of the regulatory period and subject to a "incentive based" Price cap system.
Regulatory asset base	In the first regulatory period the asset base of DSOs was re-evaluated by the Government, under the concessions contracts. New investments are considered in the RAB by its book values.
Capital expenditure	Capital costs are assessed every year. There are ex-post real values adjustments. DSO investment plans are subject to ministerial approval.
Approach to operating expenditure	Opex cost base is fixed in the beginning of each regulatory period and updated both with RPI-X and the evolution of the cost-drivers set
Form of WACC applied	Nominal, pre-tax WACC
Additional revenue items (where applicable)	The adjustment between the allowed revenue (based on estimated information) and actual revenue (recalculated with real information) is included in the allowed revenue two years later corrected by a financial compensation.

The following formula is applied in determining the weight average cost of capital WACC:

$$WACC = \frac{R_E}{1-T} \cdot \frac{E}{D+E} + R_D \frac{D}{D+E} \cdot$$

Where:

- R_D: is the cost of debt. Calculated according to the next formula:

$$R_D = R_F + RP_D$$

- R_F: is the risk free rate. This value is based on German and Portuguese government bonds. In Average over a 5 years period.
- RP_D: is the debt risk premium. This value is based on companies' analysis.
- R_E: is the real price of equity and own funds calculated according to the formula:

$$R_E = R_F + \beta_E RP_M$$

- RP_M: is the risk premium for mature market country spread. This value is based on international market analysis and expert reports.

- β_E is weighted ratio β, which defines the sensitivity of a company share to the market risk, taking into account the income tax rate and the debt share, calculated according to the formula:

$$\beta_L = \beta_A \times \left[1 + (1 - T) \times \frac{D}{E}\right]$$

- B_A. Bottom-up Betas based on benchmarking of similar companies and market analysis.
- T is the effective tax rate. National level in the beginning of the regulatory period.
- The debt leverage (Ratio E/D) is based on regulated companies´ capital structure.

3. Tariffs for distribution services

The regulator is in charge of setting the distribution tariffs according to the Tariff Code.

The distribution tariffs are setting in such a way that their components reflects the structure of marginal or incremental costs and also enables the recovery of allowed revenue for each regulated activity.

There are three groups according pressure and annual consumption.

3.1. Distribution tariffs

The regulator is in charge of setting the distribution tariffs, based on the calculation of allowed revenues. The calculation of prices is based in the methodologies detailed in the Tariff Code approved for the regulatory period, which has been put under public consultation. Each year the tariffs are subject to consultation through the Tariff Board.

There are three distribution networks tariffs according to pressure and annual consumption. These distribution network tariffs are Medium pressure (MP), Low pressure (LP) with annual consumption higher than 10,000 m^3 and Low pressure (LP) with annual consumption less than 10,000 m^3. The allocation of distribution costs to medium pressure (MP) and low pressure (LP) distribution tariffs involves the determination of long run average incremental costs for the MP network and for the LP network, whereas for the latter, values are also different for the upper and lower 10 000 m3/year deliveries. These incremental costs are further differentiated by:

- Incremental cost of used capacity
- Incremental cost of energy in peak periods
- Incremental cost of energy in off-peak periods
- Incremental cost per client, connected to the peripheral section, not incorporated into the price of the connection charge; and
- Incremental cost per customer, associated with meter reading and data processing

The Tariff Code also establishes the same distribution tariffs for all consumers, regardless of the DSO that delivers the gas. The tariffs are determined in an aggregated manner that is based on the total allowed revenues and on the total deliveries of all DSO´s.

A regulated revenue reconciliation mechanism ensures every DSO gets its own allowed revenues.

The general structure of gas tariffs defined in the Tariff code includes the following components/terms:

- Fixed term, in Eur per month
- Energy term, in Eur per kWh. Time period differentiation (Peak and off peak)
- Used capacity term, in EUR per kWh/day per month. The used capacity term of the monthly flexible distribution tariff is differenced per two year seasons.

The details of distribution tariff groups and their components are summarized in section 1.2 Key figures on revenue and tariffs.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 387: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Losses are made up for by requiring each entity responsible for balancing to deliver more gas than the one consumed by its loads.
Presence of uniform tariffs	The same distribution tariff applies to consumers everywhere in the country. No distribution tariff differentiation according DSO.
Presence of non-linear tariffs	No, all tariff components are linear. Energy component is differentiated in two periods: off peak (august) and peak (rest of the year). The used capacity term of the flexible tariff is differenced per two year seasons.
Presence of regulated retail tariffs	In compliance with national legislation and according to the calendar defined by the Government, end user tariffs published by the NRA for all customers ceased to exist on the 1st of July 2013 with the extinction of regulated end user tariffs to customers whose annual consumption is less than 500 m3, concluding the liberalization process of the natural gas retail market. Until the end of 2015, the NRA sets transitory tariffs every quarter to encourage the transition of customers

Issue	Approach
	from the regulated market to the liberalized market. Economically vulnerable customers will, however, continue to have access to regulated social tariffs, subject to the ceiling on tariff variation established annually by the Government. These vulnerable customers include consumers who are encompassed in a restricted group of government social support instruments.
Presence of social tariffs	Social network tariffs are implemented. A discount is given on the fixed term and on energy. Consumers pay the burden

There are not special incentives in network tariffs for large users, but flexible tariffs have been introduced to give more flexibility to these consumers.

Distributions tariff are published on legal NRA directive and are also available on their website (*only available in Portuguese*).

http://www.erse.pt/pt/gasnatural/tarifaseprecos/201407a201506/Documents/Diretiva%20ERSE%206-2014%20(Tarifas%20GN%202014-2015).pdf

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 388: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Connection charges are deep.
	Methodology adopted to determine connection costs	Large consumers (annual consumption higher than 10000 m^3): the cost is paid by the consumer according to a methodology established by the NRA which takes into account the pressure level, the investment and development plans of the distribution network and the extra cost of the connection. Small consumers (annual consumption less than 10000 m^3 and length of the requested connection above 100 m): the cost is estimated by the DSO and paid by the consumer. Small consumers (annual consumption less than 10 000 m^3 and length of the requested connection below 100 m): the cost of the first 10 m is paid by the DSO; the remaining cost is paid by the consumer based on prices approved by the regulator.
Hosting capacity	Scope to refuse connection	DSO must accept all the connection requests once verified the technical and legal conditions, except for small consumers if the length of the requested connection is above 100 m.
	Requirements to publish hosting capacity	No

4. Distribution system development

In Portugal, the Distribution System Plans are subject to a ministerial approved. NRA participates in the assessment of the Plan(s) with a reasoned opinion. The implementation of a new assessment/approval process is taking in place during 2014.

DSO´s have full responsibility for metering and own the metering devices. The cost-benefit analysis concluded that in Portugal the investment in smart metering is not

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 389: Approach to distribution planning

Issue	Approach
- Form of distribution planning document	According to the national legislation (decree-law nr 231/2012, of October 12), the investments plans of the distribution companies are subject to ministerial approval. The NRA participates in the assessment of the Distribution Network Investment Plan(s) with a reasoned opinion, after conducting a public consultation. The implementation of the assessment/approval process for the investments on the distribution networks is taking place in 2014, and a reviewing process will be held every two years. The final and the consultation versions of the Distribution Network Investment Plan(s) should be published, according to Decree-Law nr 231/2012 of October 12.
- Key responsibilities for its development	Once approved (see previous answer), the DSO´s are responsible for implementing their network development plans and the regulator supervises the calendar, the budget and the execution of the investments projects.
- Degree of integration with renewables plan	Not applicable.
- Relationship with quality of service targets	The investment plan(s) does not explicitly illustrate the relationship between each (type of) investment and the benefits in terms of increased quality of services. However, some of the investments considered on the plans aim at maintaining a high level of continuity of supply
- How trade-offs between network development and alternative technologies are treated	The investment plans for the distribution grids are based on conventional technologies. Up to now no relevant initiatives were taken regarding investment on smart grid technologies for gas.
- Requirements to integrate cost benefit analysis	The investment plans for the distribution grids present a series of indicators such as: • EUR per new costumer • EUR per additional KWh supplied • EUR per additional length (m) of grid installed • Length of additional pipeline per new costumer • Others In general terms, the investment decisions are based on those indicators.

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 390: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs have full responsibility for metering and own the meters.
Monopoly services in the metering	Yes
Smart metering functionality	Not applicable

Portugal concluded in 2013 a cost benefit-analysis with negative results and decided not to proceed with large-scale roll-out of smart metering systems for natural gas. No smart meters installed so far.

5. Annexes

The following tables present the regulated tariff prices for the gas year jul2013-jun2014, only referring to the distribution network cost component. Each component of the third-party access tariff is published separately by the regulator. The TPA tariff results from adding all the components. Hence, users pay not only the distribution network costs but also the transmission network and the global use of the system tariff components.

Nevertheless, here are presented the distribution network costs only.

5.1. Distribution network tariffs 2013-2014. Medium pressure

Distribution Network Tariffs - Medium Pressure

Tariffs	Tariffs options	Scale	(m^3/year)	Fixed term Measurement Daily (EUR/month)	Fixed term Measurement Monthly (EUR/month)	Energy Peak (EUR/kWh)	Energy Off-peak (EUR/kWh)	Used Capacity (EUR/(kWh/day)/month)
Distribution Network Tariff MP				426,29	426,29	0,00077826	0,00001856	0,057632
MP	Long utilization (daily measurement)			426,29		0,00077826	0,00001856	0,057632
	Short utilization			426,29		0,00681756	0,00001856	0,011526
	Long utilization (monthly measurement)		10.000 - 100.000		460,44	0,00999942	0,00923971	
			≥ 100.001		620,96	0,00503418	0,00427448	
LP>	Long utilization (daily measurement)					0,00389739	0,00001862	
	Short utilization					0,00389739	0,00001862	
	Flexible					0,00389739	0,00001862	
	Long utilization (monthly measurement)		10.000 - 100.000			0,00389739	0,00001862	
			≥ 100.001			0,00389739	0,00001862	
LP<	Other	Scale 1	0 - 220			0,00375332		
		Scale 2	221 - 500			0,00375332		
		Scale 3	501 - 1.000			0,00375332		
		Scale 4	1.001 - 10.000			0,00375332		

Distribution Network Tariffs - Medium Pressure (Flexible monthly)

Tariffs	Tariffs options	Fixed term Measurement Daily (EUR/month)	Fixed term Measurement Monthly (EUR/month)	Energy Peak (EUR/kWh)	Energy Off-peak (EUR/kWh)	Additional Monthly Capacity (April-September) (EUR/(kWh/day)/month)	Additional Monthly Capacity (October-March) (EUR/(kWh/day)/month)
MP	Flexible	426,29		0,00077826	0,00001856	0,057632	0,115264

Distribution Network Tariffs - Medium Pressure (Flexible annual and monthly)

Tariffs	Tariffs options	Fixed term Measurement Daily (EUR/month)	Fixed term Measurement Monthly (EUR/month)	Energy Peak (EUR/kWh)	Energy Off-peak (EUR/kWh)	Annual Base Capacity (EUR/(kWh/day)/month)	Additional Monthly Capacity (April-September) (EUR/(kWh/day)/month)
MP	Flexible	426,29		0,00077826	0,00001856	0,057632	0,057632

5.2. Distribution network tariffs 2013-2014. Low pressure with annual consumption higher than 10,000 m³

Distribution Network Tariffs - Low Pressure > 10 000 m³/year

Tariffs	Tariffs options	(m³/year)	Fixed term – Measurement – Daily (EUR/month)	Fixed term – Measurement – Monthly (EUR/month)	Energy – Peak (EUR/kWh)	Energy – Off-peak (EUR/kWh)	Used Capacity (EUR/(kWh/day)/month)
Distribution Network Tariff LP>			141,61	141,61	0,00569145	0,00010590	0,061100
LP>	Long utilization (daily measurement)		141,61		0,00569145	0,00010590	0,061100
	Short utilization		141,61		0,01422862	0,00010590	0,012220
	Long utilization (monthly measurement)	10.000 - 100.000		213,27	0,01546741	0,00988187	
		≥ 100.001		487,92	0,00963944	0,00405389	

Distribution Network Tariffs - Low Pressure > 10 000 m³/year (Flexible monthly)

Tariffs	Tariffs options	Fixed term – Measurement – Daily (EUR/month)	Fixed term – Measurement – Monthly (EUR/month)	Energy – Peak (EUR/kWh)	Energy – Off-peak (EUR/kWh)	Additional Monthly Capacity (April-September) (EUR/(kWh/day)/month)	Additional Monthly Capacity (October-March) (EUR/(kWh/day)/month)
LP>	Flexible	141,61		0,00569145	0,00010590	0,061100	0,122200

Distribution Network Tariffs - Low Pressure > 10 000 m³/year (Flexible annual and monthly)

Tariffs	Tariffs options	Fixed term – Measurement – Daily (EUR/month)	Fixed term – Measurement – Monthly (EUR/month)	Energy – Peak (EUR/kWh)	Energy – Off-peak (EUR/kWh)	Annual Base Capacity (EUR/(kWh/day)/month)	Additional Monthly Capacity (April-September) (EUR/(kWh/day)/month)
LP>	Flexible	141,61		0,00569145	0,00010590	0,061100	0,061100

5.3. Distribution network tariffs 2013-2014. Low pressure with annual consumption less than 10,000 m³

Distribution Network Tariffs - Low Pressure < 10 000 m³/year

Tariffs	Scale Consumption	(m³/year)	Fixed term (EUR/month)	Energy – peak (EUR/kWh)	Energy – off-peak (EUR/kWh)	Used Capacity (EUR/(kWh/day)/month)
Distribution Network Tariff LP<			0,22	0,00950773	0,00010590	0,061100
LP<	Scale 1	0 - 220	0,22	0,03908494		
	Scale 2	221 - 500	0,96	0,03494815		
	Scale 3	501 - 1.000	2,39	0,03084184		
	Scale 4	1.001 - 10.000	2,43	0,03000682		

Country Report – Romania (electricity distribution)[124]

1. Overview of to the distribution sector

In Romania operates eight legally unbundled DSO, covering the whole territory of the country.

The main responsible of the definition of the allowed revenue is the NRA. DSO´s calculates revenues and send approval requests to the regulator.

About distribution tariff, NRA sets tariffs after analysing distribution company proposals. There are public consultation processes to regulate distribution business

1.1. Institutional structure and responsibilities

In Romania there are 8 DSO supplying electricity to about 8,842 millions of customers covering the whole country. In 2013, the total amount of electricity consumed in the country was 41,010 TWh.

DSO´s with more of 100000 customers, there are legal unbundling. For small DSO´s with less than of 100000 customers, there are only functional unbundling.

Summary data on industry structure is set out below.

Table 391: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Romania	8		8	0	NO	100%
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

The responsibility for setting the allowed revenues tariffs is spread between the following jurisdictions:

- **The Parliament,** issues principles in the primary law. (Law of electricity and natural gases no. 123/2012 issued by Parliament)

[124] Pending validation from the NRA.

- **The Regulator, ANRE,** has the duty and the authority to define the methodologies used to calculate the allowed revenues and approve the revenues calculated by DSO.
- **The DSO,** calculates allowed revenue based in regulator methodology to the NRA approval.

The responsibility for the definition of distribution tariffs is spread between the following jurisdictions:

- **The Regulator, ANRE,** sets and approves tariffs after analysing DSO proposals.
- **DSO** may propose a change in the tariff structure and this new structure may be applied if the regulator accept the new tariff structure, but for a consistent period of time. All DSO apply the same tariff structure.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 392: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	The DSO calculates and send approval requests to the regulator	May propose a change in the tariff and the NRA should asses the request. All DSO apply the same tariff structure.	The DSO calculates and send approval requests to the regulator
Parliament	Defines main principles in primary law		Defines main principles in primary law
NRA	Issues a methodology, sets and approves allowed revenues	Main responsibility.	Issues a methodology, sets and connection charges

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

There are a public consultation processes and participation of DSO on distribution tariff decision:

- In the process of approving or modifying a methodology, the document is put on public consultation for one month. The methodology is approved by the Regulatory Committee in a public meeting.
- In the process of establishing, the result of the analysis is sent to DSO´s. They are invited to give their feedback about the analysis and explain their arguments. The NRA can accept or no their arguments. After that, the tariff proposal from NRA specialized department is sent to the Regulatory Committee in order to be approved. The Regulatory Committee of the Regulatory discuss and approves the tariffs in a public meeting.

1.2. Key figures on revenue and tariffs

The distribution activities revenues in 2013 were 1.14 billion of euros. No further split by activity type is considered in the regulation.

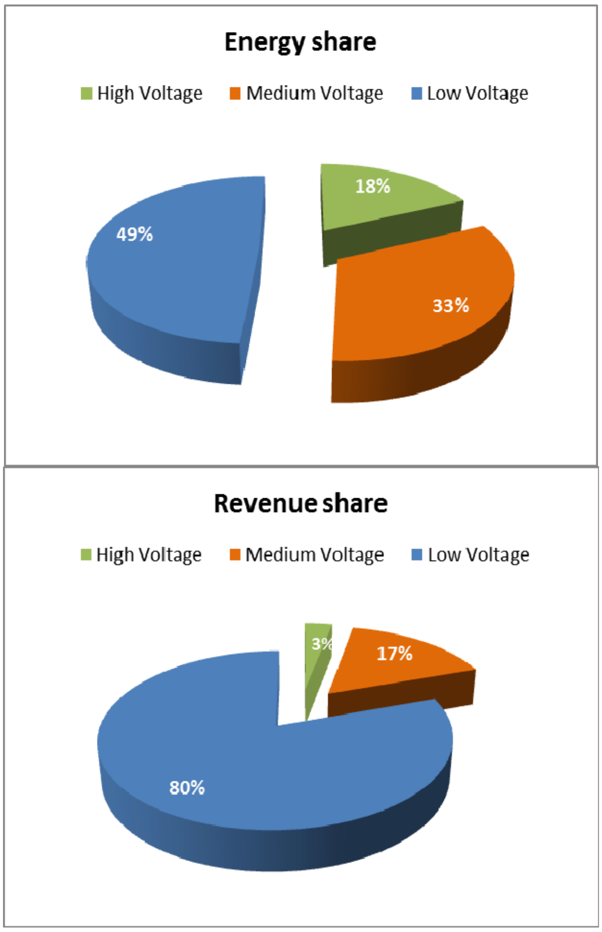
A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 393: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenue
High voltage	Energy charge (€/kWh)	256	35421092 €
Medium voltage	Energy charge	17852	188134800 €
Low voltage	Energy charge	8824027	916063416 €
Total	-	**8842135**	**1139619309 €**

The breakdown of energy volumes and distribution revenue by voltage level are set out in the charts below.

Figure 78: Proportion of energy and revenue accounted by customer categories



In Romania there is no formal definition of typical consumer category as households, small industrial and large industrial. Customer categories are defined by voltage level: High Voltage, Medium Voltage and Low Voltage.

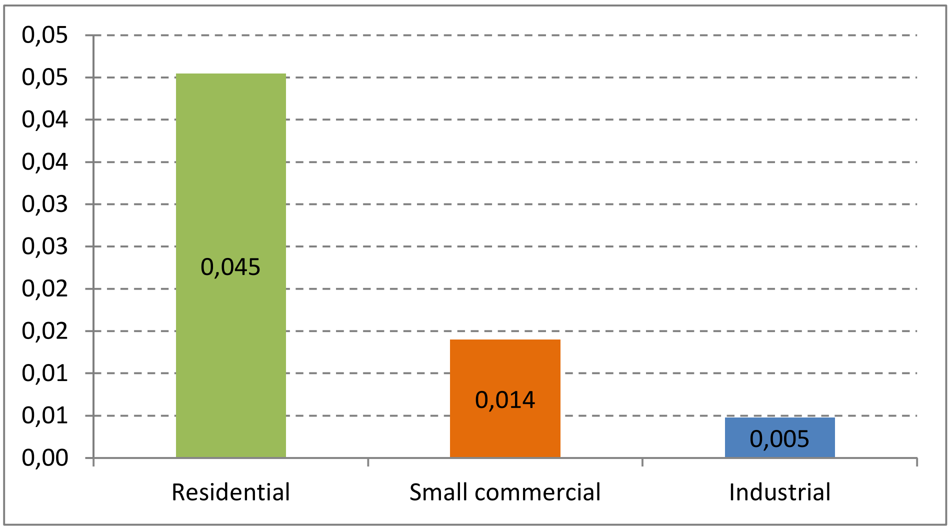
All consumers are charged only a per KWh distribution tariff. According to its electricity level, a consumer pays the sum of cascaded charges, for example a consumer from LV pays the sum of charges from HV, MV and LV. Each of the 8 DSO have the different prices (same structure), according to the allowed revenues.

Table 394: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Capacity charge	Energy charges	Reactive charges	Total
Low voltage	3500kWh	No	No	159 € (0,04552 €/kWh)	No	159 €
Medium voltage	50MWh	No	No	700 € (0,014€ /kWh)	No	700 €
High Voltage	24000MWh	No	No	114240 € (0,00476 €/kWh)	No	114240 €

The resulting average tariffs per kWh are illustrated below.

Figure 79: Average network charges (€/kWh), 2013



2. Regulation of distribution activities

Distribution activities are regulated by ANRE. Their main objectives are developing, approving and monitoring national rules necessary for the functioning of the energy sector, oriented to efficiency, competition, transparency and consumer protection.

The distribution sector is regulated under a price cap regulatory model. DSO profits are not regulated, so there are reduction cost incentives. There are other incentives as reduction of losses and quality improvement that impact in DSO profits.

2.1. General overview

According to the Electricity Law No. 13/2007, the electricity distribution shall be carried out by DSO, legal person and holder of a license. The DSO´s provide non-discriminatory electricity distribution services to all network users, ensuring the access to the grid of all applicants that meet the requirements hereof, while observing the performance standards and norms provided by technical regulations in force.

"Distribution system operator (DSO) means any person that, under any title, holds a distribution license that is operates, ensures the maintenance, and, if necessary, develops the electricity distribution network in a certain area and, where it is applicable, its interconnection with other systems, and the provide of the long term capacity of the system to answer to reasonable demands on electricity distribution".

The NRA (ANRE) is an independent and autonomous administrative regulatory authority under parliamentary control. Its mission is developing, approving and monitoring national rules necessary for the functioning of the energy sector, oriented to efficiency, competition, transparency and consumer protection.

The role of the ANRE, as the regulator, has the following duties, established by primary law:

- Set up mandatory regulations for undertakings in electricity sector
- Issue, grant, suspend or withdraw authorisations and licenses for undertakings in electricity sector
- Define technical and commercial regulations, ensure users connection to the electricity and gas grid
- Establish and approves pricing methodologies and tariffs
- pricing methodologies and tariffs
- Ensure the monitoring of electric power and gas market operation
- Promote renewable energy production

According to this, the distribution sector is regulated under an Incentive-based, price-cap regulatory model, where the DSO estimates tariff, according to the approved methodologies, and the regulator fixes and approves the final tariffs.

Key features of the regulatory regime are set out in the following table

Table 395: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	DSO are private owned. Concession refers only to the service providing. The period of concession is 49 years with a possibility to extend the contract for another half of this period. Also they have licence for distribution service for 25 years. Basically, the concession is allocated through a competitive mechanism in an indirect manner, because DSO were privatized through auctions.
Duration of tariff setting regime	5 year
Form of determination (distributor propose/regulator decide)	Distributor proposes/regulator approves
Scope for appeal regulatory decision	Public consultation processes

2.2. Main incentive properties of the distribution regulatory model

The regulatory model provides the following incentives:

- There is no limit on overall yearly profit
- Reduction of OPEX (Operative and maintenance costs). Above 50% of operation and maintenance costs efficiency gain is transferred to customers, the other 50% to the DSO.
- Reduction of distribution network losses. Between 50% and 75% of losses efficiency gain are transferred to customers, the rest to the DSO.
- Quality improvement. Allowed revenues are increased (decreased) if he DSO performs better (worse) than some predefined quality targets.
- A methodology to implement a quality factor that will incentivize operators by decreasing or increasing the total allowed revenue for each operator according to its quality performance will be implemented soon.

Otherwise the DSO´s completely bear the costs of unrecognised losses, if the amount of operation and maintenance costs that exceed the approved level.

At the same time the following tools are provided to mitigate risks:

- Yearly correction according to (demand reducing/increasing), on each voltage level. The influence of the demand changings is taken into account also in the correction of the cost of yearly losses.
- Some costs are considered non-controllable as:
    - Costs with taxes and royalties set according to the legal provisions in force or by the local authorities
    - Contributions to the health fund, special fund and other similar contributions related to the wages but excluding the alternative health and pension systems
    - The regulated transformation/connection, distribution costs generated by the use of transformers/substations, lines owned by other companies
    - Extraordinary costs determined by major force (maintenance caused by important and not predictable natural events);

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 396: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Price Cap regulation
Regulatory asset base	Based on an initially RAB value (2004) at the moment of implementing the incentive based regulation. This value is depreciated for a period of 25 years and actualised with consumer price index. New investments enter with initial book value. The residual values are actualised with consumer price index.
Capital expenditure	There are three main categories of investment, based on investment's importance and necessity. There are also provisions that mention the criteria of accepting the investments The regulator analyzes investment programs submitted by DSO. Overall investment value based on investment programs and are subject to an ex-ante approval by the regulator.
Approach to operating expenditure	NRA used comparative analysis to set the operation and maintenance cost and the level of accepted electricity losses, but these were not based on DEA, COLS or SFA
Form of WACC applied	The financial structure in the WACC formula is set by the regulator. There is no adjustment ex-post
Additional revenue items (where applicable)	

The following formula is applied in determining the WACC:

$$WACC = CCP \times \frac{Kp}{(1-T)} + CCI \times Ki$$

Where:

- CCP is the after-tax cost of equity in real terms, recognized by the competent authority (%)
- CCI - the pre-tax cost of debt in real terms, recognized by the competent authority (%)
- Kp - the share of equity in total capital structure, set by the competent authority
- Ki - the share of debt in total capital structure set by the competent authority. Ki = (1-Kp)
- T - the profit tax rate.
- CCP = Rf + (Rm - Rf) * β, where:
- Rf - the risk free rate (e.g. interest rate for T-bonds/T-bills)

- Rm - the capital markets risk (return over the market portfolio) (Rm - Rf) is the market risk premium
- β the coefficient that express the correlation between the market return and company's return and represents a comparison of the market risk.

The WACC is not review during the regulatory period.

3. Tariffs for distribution services

The NRA is in charge of setting and approval the distribution tariffs according to DSO proposes.

The methodology to allocate distribution costs is based in cost categorization by voltage level and regulator methodology.

There are three classes of consumers: HV, MV, LV consumers. The tariffs have only one energy component. There is no time of use differentiation.

Connections charges for MV and LV consumers pay a fixed fee approved by NRA. For HV consumers or generators the DSO makes an estimate based on its cost.

3.1. Distribution tariffs

DSO is in charge of calculating the distribution tariffs according to the methodology defined by the regulator. The NRA sets tariffs after analysing distribution company proposals.

Three categories of costs are identified: HV costs, MV costs, LV costs. Costs (excepting the electricity losses) are split on each level according to an allocation key determined by the DSO according to economic causality and direct occurring of costs.

The cost of losses is calculated for each electricity level according to the amount on losses on each level. The costs on each level (losses plus the other allocated costs) are recovered through a per MWh tariff component set for each level.

Basically, the distribution tariff consists on an energy component which includes the distribution losses for each consumers group. There is not use-time differentiation.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 397: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Losses are includes in the KWh component
Presence of uniform tariffs	Each DSO has their own prices for the same voltage level (according allowed revenues)
Presence of non-linear tariffs	No, All tariff components are linear There are not use-time differentiation

Issue	Approach
Presence of regulated retail tariffs	The retail tariffs are regulated only for households until 2017.
Presence of social tariffs	No.

Generators connected to the distribution grid do not pay any distribution tariff. There are not special incentives in network tariffs for large users like power plants.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 398: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	For small generators/consumers, the generator bear the grid connection cost but not the grid reinforcement cost (shallow) For generators, they charge the costs of new infrastructures and the costs of the reinforcement of networks(deep)
	Methodology adopted	For the connection to low and medium voltage network, there are connection fees approved by the regulator. For larger consumers or generators, connection costs are computed case by case. the DSO makes an estimate based on its cost
Hosting capacity	Scope to refuse connection	The DSO can refuse connection only if the connection affects the safety of National Electricity System by non-compliance with the technical and performance standards set out in technical regulations or where the transmission or distribution network lacks the necessary capacity. Refusing must be motivated on objective criteria, properly justified technically and economically.
	Requirements to publish hosting capacity	No requirement on the DSO to publish hosting capacity information
	Targets and/or incentive schemes to enhance hosting capacity	No

4. Distribution system development and operation

The distribution system development plans are design by DSO´s and approved by the regulator. In order to be accepted by the regulator, investments should be prudent, necessary, opportune, efficient and should reflect the market conditions.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 399: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Distribution system development plan notified to the regulator but not approved nor published. Also there are detailed investment plans that can be treated as development plan. They are approved by the regulator and not published.
- Key responsibilities for its development	DSO´s design and The NRA approves
-Degree of integration with renewables plan	Distribution network plans are designed by DSO taking into account the connection requests
- Relationship with consumption trends	Distribution network plans are designed by DSO taking into account the evolution of consumption on the base of their forecasts
-Relationship with quality of service targets	Distribution network plans are designed by DSO taking into consideration the necessities of ensuring an appropriate level of quality by including the necessary investments. If the quality targets are not reached, DOS receive penalties. Also, it will be implemented soon a methodology to implement a quality factor that will incentivize DSO by decreasing or increasing the total allowed revenue for each operator according to its quality performance
-How trade-offs between network development and alternative technologies are treated	DSO should consider the necessity of implementing smart metering infrastructure, so there are trade-offs imposed by the upper reasonable value of investment that can be accepted in tariff calculation.
- Requirements to integrate cost benefit analysis	The network development plan reports only the decisions of the DSOs. In order to be accepted by the regulator, investments should be prudent, necessary, opportune, efficient and should reflect the market conditions.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 400: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	DSO is placed at the third level of dispatching rights, under the command of Den (National Dispatch Center)
Possibility to dispatch flexible loads	The DSO is entitled to interrupt or can limit the load for safety reasons, in emergency cases
Other sources of flexibility open to DSO	NA

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 401: Key approach to metering

Issue	Approach adopted
Discos role in metering	Full responsibility for metering, and own the meters
Monopoly services in the metering	DSO is the only authorized entity in charge of metering activities in its jurisdictions, but they may externalize the activity.
Smart metering functionality	The main functions requires are: • Quarter-of an hour measurement • Remote reading • Remote disconnection/reconnection of customers • Remote control of the maximum power that can be withdrawn

The deployment of smart meters is in the stage of approval of the pilot-projects, there are 120 000 clients included in this stage, whose main features were:

- Quarter-of an hour measurement
- Remote reading
- Remote disconnection/reconnection of customers
- Remote control of the maximum power that can be withdrawn

Country Report – Sweden (electricity distribution)

1. Overview of to the distribution sector

There are 8 large DSOs in Sweden; various DSOs supply small customer bases, providing around one half of the total national electricity demand.

The NRA is responsible for calculating the amount of allowed revenues

DSOs are in charge of setting the tariffs, and that they can use any methodology they prefer as long as that methodology is non-discriminatory and objective.

1.1. Institutional structure and responsibilities

In Sweden there are 8 main distributors supplying electricity to around 5,2 million customers. The electricity network consists of 538000 kilometers of conductors, of which 320000 kilometers are underground cables and 218000 kilometers are overhead lines.

Summary data on industry structure is set out below.

Table 402: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	8	All	All	3	No	47,7%
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

The DSO has the responsibility for deciding the tariff structure. Individual cases may be assessed by the regulator according to the non-discriminating requirements.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 403: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Not directly involved	Decides on the tariff structure	Decides the connection charges

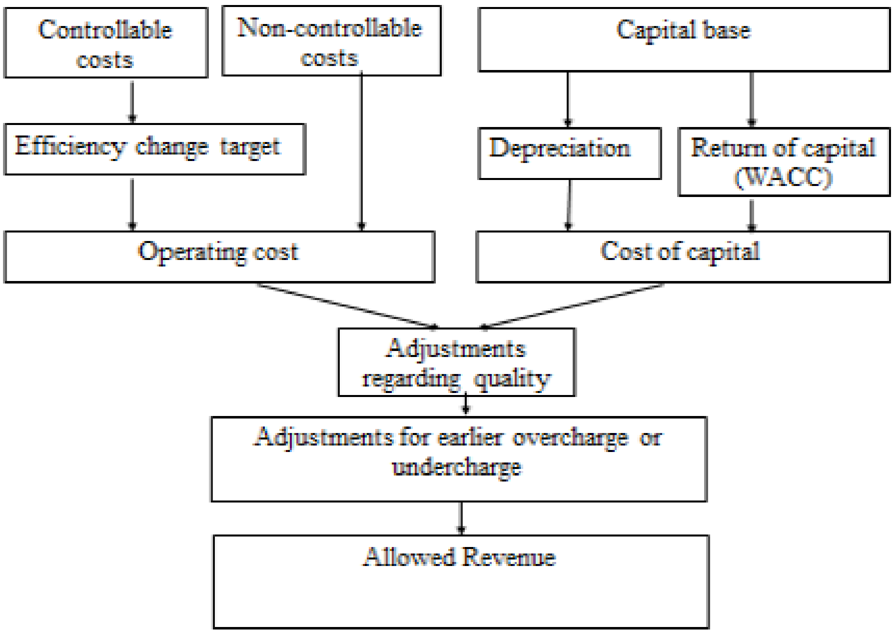
Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
Government	Issues the principles to be followed through primary law	Not involved	Issues the principles to be followed through primary law
NRA	Issues a methodology and calculates the allowed revenues	May take decisions on tariff structures in individual cases, according to non-discriminating requirements	May assess individual cases, according to a methodology that is decided by the NRA

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process for setting distribution tariffs specifies that the DSO is in charge of setting the tariffs, and that they can use any methodology they prefer as long as that methodology is non-discriminatory and objective.

The structure for the calculation of a DSO´s revenue cap and allowed revenue is shown Figure 80:

Figure 80: Methodology for the calculation of allowed revenue and the revenue cap



Source: Nordic Energy Regulators, 2013[125]

1.2. Key figures on revenue and tariffs

[125] Nordic Energy Regulators, 2013. Economic regulation of electricity grids in Nordic countries. Received from: http://www.nordicenergyregulators.org/wp-content/uploads/2013/02/Economic_regulation_of_electricity_grids_in_Nordic_countries.pdf

The allowed revenues were € 3,295 billion in 2012. However, information on the revenues and energy consumption proportions of each customer category is not available.

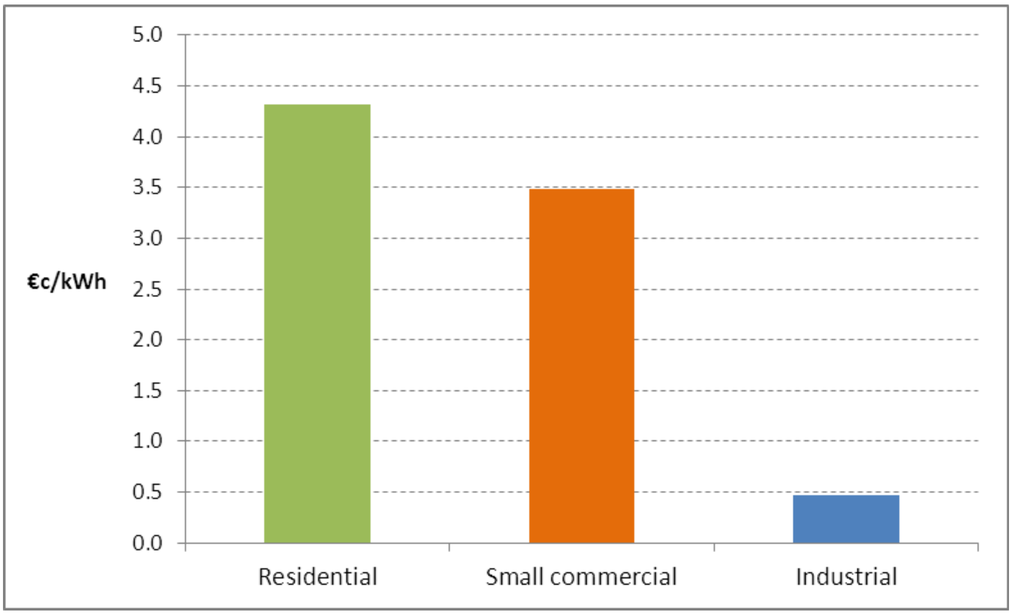
The typical network tariff in 2013 for residential, small and large industrial customers is illustrated below:

Table 404: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Demand and reactive charges	Total
Residential	3500kWh	96	55		151
Small commercial	50MWh	760	985		1.745
Industrial	24000MWh	1.154	110.400		111.554

The resulting average tariffs per kWh are illustrated below.

Figure 81: Average network charges (€cents/kWh), 2013



2. Regulation of distribution activities

A mixed regulatory regime is in place, which includes both cost-reimbursement and incentive-based components.

Incentive aspects include measures to reduce the controllable operational costs, and to achieve quality of service targets.

2.1. General overview

The role of the DISCO in Sweden is to develop tariffs which are competitive and therefore to promote retail market competition. The NRA is responsible for calculating the allowed revenues, but is generally not involved with setting the allowed tariff structures (which individual DSOs are required to do).

The distribution sector is regulated under a mixed regulatory regime, which includes both cost-reimbursement and incentive-based components. Key features of this regime are efficiency targets for costs that are considered controllable, service quality measurements, and revenue caps.

Key features of the regulatory regime are set out in the following table

Table 405: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession regime
Duration of tariff setting regime	4 years
Form of determination (distributor propose/regulator decide)	Distributor develops and decides on the tariff. The distributor can use any methodology they prefer as long as it is non-discriminatory and objective.
Scope for appeal regulatory decision	Not specified

A concession regime is in effect. Concessions last indefinitely, and are not allocated through a competitive mechanism.

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- To reduce the controllable operational costs, and
- Quality of service targets

There are no risk mitigation mechanisms in place under the Swedish regulatory system.

In relation to quality of service aspects, the allowed revenues of a DSO are increased or decreased if the DSO performs better or worse than the predefined quality targets. Quality of service measures within the regulation are essentially the calculated costs of interruptions for the customers. Actual interruption costs are compared to a reference annual level. In the event that there are deviations from quality reference levels of +/- 3 % of the agreed revenue level, the revenue cap is adjusted accordingly.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 406: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue based with efficiency and performance cost components
Regulatory asset base	Planned investments in the forthcoming regulatory period are included within the RAB. Four methods can be used to value assets to be rolled into the RAB: standard values, acquisition value, book value and valuation by other way. The methods shall be used in descending order.
Capital expenditure	A product of a decided rate of return on assets, the calculated capital base and chosen depreciation times.
Approach to operating expenditure	Controllable and non-controllable – as historical costs taken from audited data from book-keeping; non-controllable costs can be passed through to consumers
Form of WACC applied	Real WACC, capital base is based on an annuity approach
Additional revenue items (where applicable)	

The following parameters are used in the formula for determining the WACC:

- Risk free rate: Nominal interest on government bonds on long run. Estimated to 4% nominal and 2% real for a 30-year perspective
- Inflation: 1,99 %
- Asset beta: 0,38 %
- Equity beta: 0,66
- Market risk premium: 4,75 %
- Premium for lack of liquidity: 0,5 %
- Capital structure (debt / equity): 50/50
- Tax rate: 20 %
- Debt premium: 1,49

3. Tariffs for distribution services

DSOs can use any (objective and non-discriminatory) methodology it chooses to allocate costs between customer categories

Regarding connection costs, and determining the levels to be used, a deep charging methodology can be applied in some instances. If the reinforcement costs are specific to the customer, they are included in the connection costs.

3.1. Distribution tariffs

In relation to the allocation of costs between customer categories, a DSO can use any methodology it prefers as long as it is non-discriminatory and objective.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 407: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Yes, the network losses are included in the revenue limit and thus also in the tariffs.
Presence of uniform tariffs	No
Presence of non-linear tariffs	Yes
Presence of regulated retail tariffs	No
Presence of social tariffs	No

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 408: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	In some cases, yes.
	Methodology adopted	DSO decides the connection cost. Customer can request a review by the NRA if it is unsatisfied.
Hosting capacity	Scope to refuse connection	No.
	Requirements to publish hosting capacity	No.
	Targets and/or incentive schemes to enhance hosting capacity	No.

Regarding the means of determining the connection charges to be used, they can be deep in some instances. Specifically, if the reinforcement costs are specific to the customer, then they are included in the connection costs.

4. Distribution system development and operation

Neither the DSOs nor the NRA are required to create a distribution system development plan

There are no restrictions placed on DSOs´ rights to dispatch renewable generators, and other sources of flexibility / regulation, which are connected into their networks

As of 2013 every customer in Sweden had a smart meter installed capable of measuring consumption on an hourly basis and which is read at least on a monthly basis

4.1. Distribution system development

There is no distribution system development plan in Sweden.

Table 409: Approach to distribution planning

Issue	Approach
Form of distribution planning document	None
- Key responsibilities for its development	N.a.
- Degree of integration with renewables plan	N.a.
- Relationship with consumption trends	N.a
- Relationship with quality of service targets	N.a.
- How trade-offs between network development and alternative technologies are treated	N.a.
- Requirements to integrate cost benefit analysis	N.a.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 410: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	DSOs can dispatch renewable plants connected to their networks
Possibility to dispatch flexible loads	Yes.
Other sources of flexibility open to DSO	Not specified

There are no restrictions placed on DSOs´ rights to dispatch renewable generators, and other sources of flexibility / regulation, which are connected into their networks.

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 411: Key approach to metering

Issue	Approach adopted
Discos role in metering	Responsible for metering; cannot own the meters; responsible for collecting data from meters; responsible for all other data management functions (including the validation, storage and sending data to the parties entitled to access them).
Monopoly services in the metering	Yes
Smart metering functionality	Half-hourly meter reading Ability to disconnect and reconnect remotely Remote data reading

As of 2013 every customer in Sweden had a smart meter installed capable of measuring consumption on an hourly basis and which is read at least on a monthly basis. This is around 5,2 million customers. No national definition of smart meters exists.

The Swedish NRA understands that no specific analysis has been undertaken on the impacts of installed smart meters on consumption and costs for customers.

Country Report – Sweden (gas distribution)

1. Overview of to the distribution sector

The gas distribution market in Sweden is highly-concentrated, with only a few DSOs operational.

The NRA is responsible for calculating the amount of allowed revenues; DSOs are responsible for deciding on the tariff structures they opt to use.

DSOs are also responsible for deciding on the connection charges they offer to new customers seeking connections.

1.1. Institutional structure and responsibilities

In Sweden there are 5 large distributors (of which the 3 largest had a collective market share of around 85%) supplying gas to 37000 customers (of which 3600 are company customers and the rest are household customers)[126] covering an area of 14379 km^2. Summary data on industry structure is set out below.

Table 412: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Country	5	All	All	5	No	100%

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**

The responsibility for setting distribution tariffs is spread between the following jurisdictions:

- The DSO decides on the tariff structure;
- The NRA may assess the adequacy of a proposed tariff structure, on the basis of tariff non-discrimination requirements; and
- Government is not involved.

[126] CEER, 2012. National report – Sweden. Received from: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202012/NR_En/C12_NR_Sweden-EN.pdf

The breakdown of responsibilities as it relates to tariff setting is summarized in the table below.

Table 413: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Not directly involved	Decides the tariff structure	Decides on the connection charges to be implemented
Government	Defines main principles in primary law	Not directly involved	Defines main principles in primary law
NRA	Issues a methodology and calculates the allowed revenues	May assess tariff structures on an individual basis, according to non-discriminating requirements	Not directly involved

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process used to set distribution tariffs is that the DSOs decide on the tariff structure to be implemented. The NRA may get involved in investigating tariff structures on an individual basis according to non-discriminatory requirements.

1.2. Key figures on revenue and tariffs

The Swedish NRA understands that information is not available concerning the revenue from each Swedish customer category. Similarly, information is not available concerning the proportional contribution of each customer category to total gas distribution for consumption.

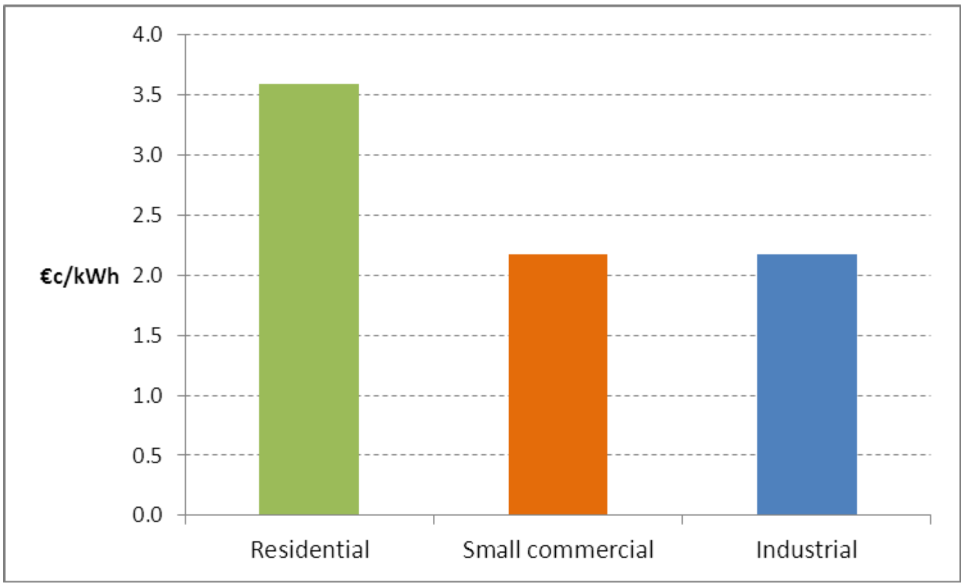
However, a typical network tariff in 2013 for residential, small and large industrial customers is illustrated below. It must be noted that various tariffs exist in Sweden, and which are specific to each particular DSO; therefore, please not that annual charges stated below are to be considered as representative only.

Table 414: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Total
Residential	15000kWh	122	417	539
Small commercial	50000000 kWh	313	1085000	1085313
Industrial	90000000 kWh	313	1953000	1953313

The resulting average tariffs per kWh are illustrated below.

Figure 82: Average network charges (€cents/kWh), 2013



2. Regulation of distribution activities

A mixed regulatory model is used in Sweden´s gas distribution sector. CAPEX is calculated based on fixed asset replacement values; OPEX are divided into controllable costs (which include efficiency targets) and non-controllable costs (where actual costs are used). Tariffs are set for 4 years.

2.1. General overview

The role of the DSOs in Sweden is to set the distribution tariff structures they offer to customers, based on their allowed revenues (which is decided by the NRA). The Government is not involved in the process of calculating the allowed revenues, beyond issuing the main guiding factors in the principle law.

The distribution sector is regulated under a mixed regulatory model, wherein capital costs are calculated based on their fixed asset replacement values. Operational costs, on the other hand, are divided into two parts, namely controllable and non-controllable costs. Efficiency targets are applied on costs that are considered to be controllable, and actual costs are used for non-controllable costs.

Key features of the regulatory regime are set out in the following table:

Table 415: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession regime, of 40 year duration. Concessions are not allocated via a competitive mechanism

Duration of tariff setting regime	4 years
Form of determination (distributor propose/regulator decide)	In determining the tariff levels (allowed revenues) the Government dictates the main principles of the tariffs, and the NRA develops the methodology for calculating the tariffs

2.2. Main incentive properties of the distribution regulatory model

Incentives to reduce controllable OPEX costs are used.

There are no tools in effect to mitigate risks. The risks relate to the cost of capital.

There are no regulatory measures in effect in relation to quality of service aspects of performance.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 416: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue based with efficiency adjustments
Regulatory asset base	No regulatory approval required for rolling investment costs into the RAB.
Capital expenditure	Calculated as fixed asset replacement value
Approach to operating expenditure	Split out as controllable costs (efficiency targets applied) and non-controllable costs (actual costs are used)
Form of WACC applied	Currently under review

The WACC formula is currently under review in Sweden and three approaches to the WACC calculation are (in October 2014) being analysed in terms of their potential viability of application within the Swedish regulatory regime.

If there are any deviations from the decided revenue cap – that is, if the grid operator's actual revenue during the regulatory period deviates from the NRA's decided revenue cap – then the excess/deficit amount will decrease/ increase the subsequent regulatory period's revenue cap. If the actual revenue exceeds the cap by a value greater than 5%, an overbilling addition will reduce the revenue cap for the subsequent regulatory period. The overbilling addition is a rate equal to the average reference rate according to 9 § Interest Act (1975:635), with an addition of fifteen percentage points.

3. Tariffs for distribution services

DSOs set their own distribution tariff structures. Connection charges for new customers can be either deep or shallow in nature. Connections can be refused if the DSO does not have sufficient hosting capacity in its network.

3.1. Distribution tariffs

DSOs are in charge of setting their respective distribution tariffs, based on its allowed revenues. Specifically, DSOs can use any methodology they prefer as long as it is non-discriminatory and objective.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 417: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included within the tariffs
Presence of uniform tariffs	No, structures vary between DSOs
Presence of non-linear tariffs	Yes
Presence of regulated retail tariffs	No
Presence of social tariffs	No

Tariffs are published individually by the DSOs.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 418: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Can be either – if the costs of reinforcement of the grid are specific to a particular customer, that customer will have to pay them. A customer may therefore have to pay deep costs (related to grid reinforcement).
	Methodology adopted	The DSO decides the connection cost to be applied. If a customer is not satisfied with the DSO´s offered cost, it can request that the NRA re-assess the costs.
Hosting capacity	Scope to refuse connection	A connection can be refused if the DSO believes the connection is not possible under reasonable conditions and/or if there is not adequate hosting capacity.
	Requirements to publish hosting capacity	No.
	Targets and/or incentive schemes to enhance hosting capacity	None.

DSOs are obliged to connect renewable plants into their distribution networks if it is technically and economically feasible to do so.

4. Distribution system development and operation

DSOs do not develop and submit distribution planning documents. There is no regulation or specific requirements governing DSOs´ need to achieve a trade-off between their network development objectives and the treatment of alternative technologies.

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 419: Approach to distribution planning

Issue	Approach
Form of distribution planning document	None. There is no document related to the distribution system plan, either published and/or submitted to the NRA
- Key responsibilities for its development	N.a.
- Degree of integration with renewables plan	N.a

Issue	Approach
- Relationship with consumption trends	N.a.
- Relationship with quality of service targets	N.a.
- How trade-offs between network development and alternative technologies are treated	The relationship is not regulated, and hence the relationship will vary nationally, and informally, depending on the preferred approach of each DSO
- Requirements to integrate cost benefit analysis	The relationship is not regulated, and hence the relationship will vary nationally, and informally, depending on the preferred approach of each DSO

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 420: Key approach to metering

Issue	Approach adopted
Discos role in metering	Responsible for metering and data management. Cannot own the meters
Monopoly services in the metering	No
Smart metering functionality	Information not available

The DSO is responsible for metering, but cannot own the meters. On the data management side, the DSO is responsible for collecting the meter data, and is also responsible for other data management functions, including the validation, storage and sending data to parties which are entitled to access them.

As of 2013 there were 1265 smart meters installed in Sweden. A breakdown by customer category is illustrated below.

Table 421: Number of smart meters installed – by end of 2013

Customer category	Number
< 1,2MWh	0
1,2MWh - 300MWh	502
300 MWh - 3.000MWh	505
> 3.000 MWh	258
Total	1.265

It is understood that there is no specific information relating to the impact(s) of the roll out of smart meters in Sweden. This is likely due to the fact that meter roll out is currently in an early phase, and impact analysis will be undertaken in coming years when the scope for measuring impacts is larger, when there will be a larger pool of households on which to base analyses.

Country Report – Slovenia (electricity distribution)

1. Overview of the distribution sector

1.1. Institutional structure and responsibilities

There is only one electricity DSO for the entire territory of Slovenia. The state owned electricity DSO leases the infrastructure and activities related to performance of the DSO from the companies, which are legally separated from electricity suppliers.

Table 422: DSO characteristics

Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 customers	Exemption*	Share of total demand
1	-	1	-	Producers do not pay the network charge	N.A.
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**					

The breakdown of responsibilities about tariff setting is summarized in the table below.

Table 423: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO			
Government	Issues primary law	Issues primary law	
NRA	Sets a general act with methodologies, and charges	Sets a general act with methodologies, and charges	Sets a general act with methodologies, and charges

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The Energy Agency, in accordance with the legislation, before the start of the regulatory period is obliged to publish draft terms and a general act, which sets the methodologies. The documents and public consultation are published on the website of Energy Agency for one month. During the public consultation, public hearings are organised for individual areas. After that period, the Energy Agency publicly issues its position on comments. The draft of the general act is approved by the Energy Agency's Council.

1.4 Key figures on revenue and tariffs

Distribution allowed revenues in 2013 were 252,9 million EUR. No further split is available.

A breakdown of the number of customers, energy delivered and the revenue by customer category, including information on available tariff components, is set out in the table below.

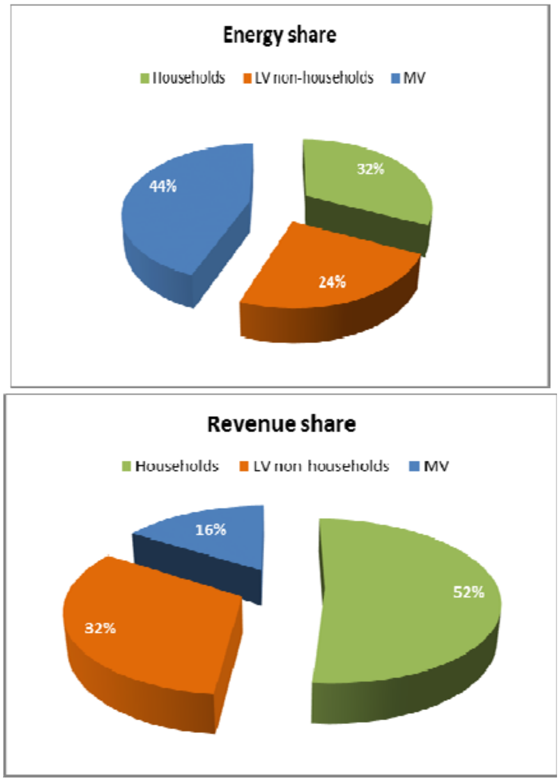
Table 424: Consumption, customers and revenues per customer class

DSO in 2013

Volage level		Type of consumption	Number of Customers	Consumption (kWh)	Revenue from distribution tariff (EUR)
MV	direct from Substation	T ≥ 2500 ur	14	712.235.587	40.440.248
		T < 2500 ur	less than 5	1.679.203	
		T ≥ 2500 ur	822	3.345.014.778	
		T < 2500 ur	689	426.338.507	
LV	direct from Substation	T ≥ 2500 ur	305	169.195.490	81.962.106
		T < 2500 ur	322	61.703.909	
		T ≥ 2500 ur	3.495	893.798.453	
		T < 2500 ur	8.055	489.635.860	
		Without power registration	91.426	980.825.024	
		Household	827.902	3.238.688.206	130.476.320

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 83: Proportion of energy and revenue accounted by customer categories



Considering also Figures 2 and e below, the split seems biased against intermediate customers.

For benchmarking, Slovenia uses the definitions from EUROSTAT. (Households D_a- D_e and industries $I_a – I_f$).

The average tariffs per kWh for the main groups of customers and for representative customers, as of 1.1.2013, are illustrated below.

Figure 84: Average network charges by main consumer groups(€c/kWh)

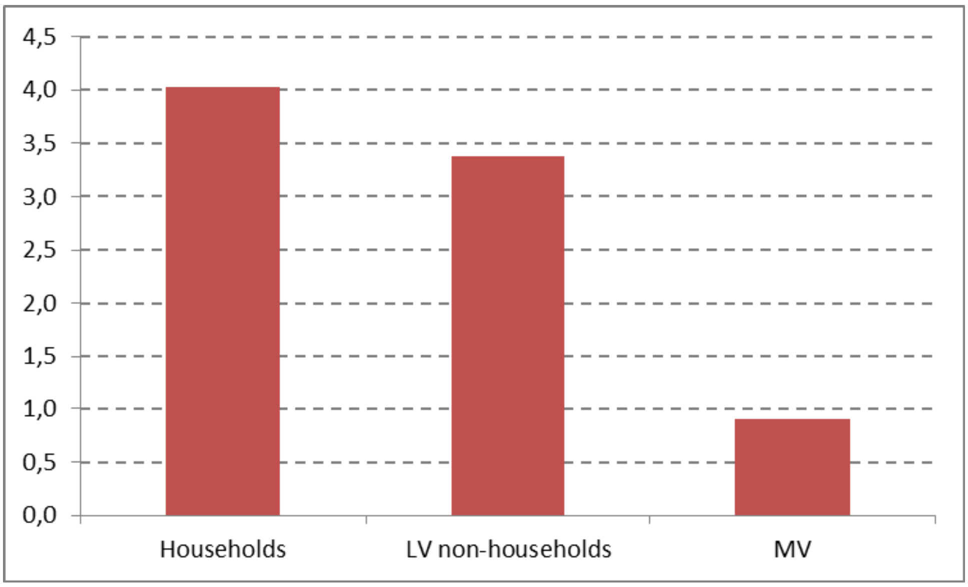
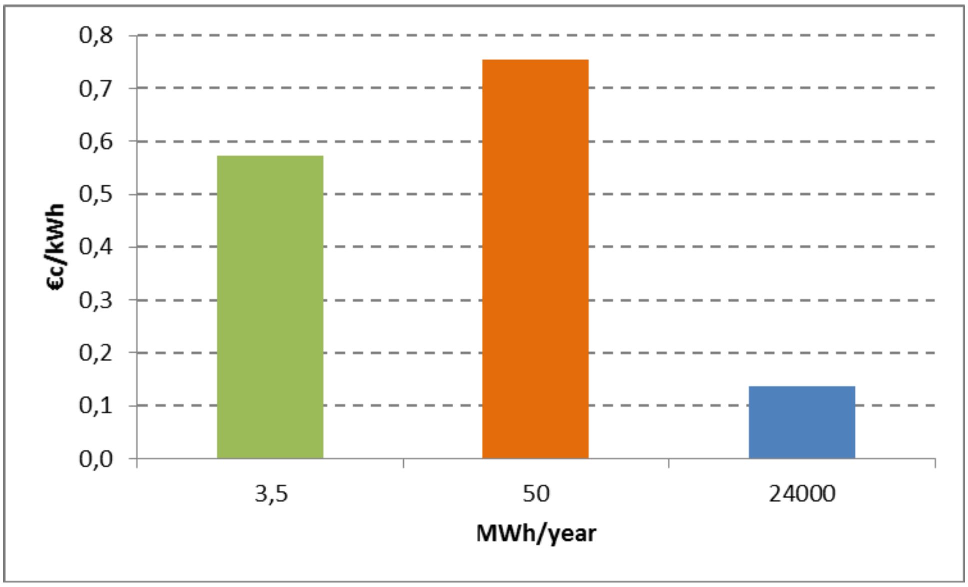


Figure 85: Average network charges for representative consumers



2. Regulation of distribution activities

2.1. General overview

Key features of the regulatory regime are set out in the following table.

Table 425: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession (50 years)
Duration of tariff setting regime	3 years
Form of determination	NRA sets the allowed revenue and tariff structure
Scope for appeal regulatory decision	N.A.

2.2. Main incentive properties of the distribution regulatory model

The broad regulatory model is incentive based. Incentives depend on:

- achieving lower costs than eligible;
- level of the quality of supply;
- investments in smart grids.

If the costs of the system operator are lower than actual eligible costs, the DSO may keep the difference. The incentives for the achieved level of the quality of supply are determined according to the deviations of the achieved level of the continuity of supply from the reference level and it results in reducing or increasing the eligible costs. If the system operator realizes investments in smart grids set by the methodology, a single grant (stimulation) equal to 2% of the current value of the asset is recognized.

A "regulatory account" mechanism is at work. After every regulatory year, the system operator determines the difference between planned and actual eligible costs of the system operator and the difference between planned and actual financing sources for covering eligible costs. By the methodology of regulated network charges, the system operator is obliged to consider the surplus of the network charge as dedicated revenue for covering the deficit of the previous years or the eligible costs of the following years. At the same time, the system operator has the right to enforce the network charge deficit in establishing the network charge in coming years.

If the Energy Agency establishes that in each year of the regulatory period significant changes in the operation of the system operator occur (i.e. a change in electricity consumption with respect to planned consumption to the extent that results in more than 10% impact on the planned network charge), the regulatory framework planned network charge revenues are amended. A change in percent of network charge tariff rates should ensure that by the end of current regulatory period the planned network charge, together with realised network charge from the beginning of the regulatory period and until the corrections of tariffs rates, equals the planned network revenue in the current regulatory period.

The regulatory framework can be modified during the regulatory period, if the Energy Agency establishes that significant changes within the operation of the system operator occur. The Energy Agency shall issue a separate decision, if it concludes that differences between eligible and actual costs were not calculated in accordance with the methodology.

The allowed revenue is defined on assumptions of the following outputs:

- GWh delivered through the distribution network
- Number of consumers connected
- Quality of service

2.3. Determination of cost of service parameters

The regulatory asset base includes only tangible fixed assets in use and the intangible assets that constitute a prerequisite for carrying out the activity of the system operator.

The book value of the assets enters the rate base.

The approach to determining key cost of service parameters is summarized in the following table.

Table 426: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue cap
Regulatory asset base	Book value
Capital expenditure	Assessed every year
Approach to operating expenditure	Assessed every year
Form of capital remuneration applied	Real WACC
Additional revenue items (where applicable)	Allowance for smart grid investment (*)

(*) A one-off additional 2% yield in the year of activation of the assets applies for the Smart Grid projects of a total value exceeding € 200,000

In the current regulatory period (2013—2015) the Energy Agency requires the reduction of annual controlled operating and maintenance costs for:

- The planned standard rate of productivity of the economy;
- The individual level of efficiency, which is determined on the comparative analysis of the effectiveness (benchmarking study);
- Additional efficiency improvements related to the costs of meter reading (which are determined on the basis of planned meters installed, enabling remote meter reading, according to individual areas of the distribution network, and projected average savings per meter).

The return on assets is evaluated on the basis of the average regulatory asset base, considering pre-tax weighted Average Cost of Capital (WACC).

$$WACC_{pre-tax} = g \cdot r_d + \frac{1}{1-t} \cdot r_e \cdot (1-g)$$

where:

- ✓ $r_e = r_f + \beta * MRP$ is the cost of equity
- ✓ MRP is the Market Risk Premium
- ✓ R_d is the cost of debt
- ✓ t is tax shield

The debt leverage is set at a target ratio considered as efficient by the regulator. There is no adjustment ex-post.

Allowed revenues are increased (decreased) if the DSO performs better (worse) than some predefined quality targets.

Also. automatic compensations are granted to consumers in case some quality standards are not met. The cost of compensations is not included in the allowed returns of the DSOs

3. Tariffs for distribution services

The tariff structure includes two time zones and is based on energy only for smaller customers, and on peak and energy for metered loads. There are also fixed terms, which cover metering costs.

3.1. Distribution tariffs

The method of cost sharing between the network users is based on the gross method, which determines that the costs of each level are allocated to consumers of established tariffs groups on each voltage level in proportion to the consumption of this level, with respect to the total consumption of other levels. In addition of their costs, the network users of lower levels are charged for a proportional share of the use of higher levels of the network. In determining the ratio between the individual tariffs groups, all eligible costs, incurred to the transmission and distribution system operators, are taken into account (operation and maintenance costs, depreciation, losses, return on assets).

For the identification of consumer groups, see Table 3 above.

There are no further splits by distribution activity.

Both components (for kW and Kwh) are different by time of use. In winter period tariffs are higher than in summer period.

Energy components (for kWh) are time differentiated for working days. Tariffs are higher from 6 to 22 and lower in rest of hours and in nonworking days.

No other costs are included in distributional tariffs.

Generators are obliged to pay distribution tariff only if they use (demand) energy from the distribution grid. In these cases, DSO charge generators according to the tariff structure for the consumers.

Table 427: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included in distribution tariffs
Presence of uniform tariffs	Yes, for the whole country
Presence of non-linear tariffs	No
Presence of regulated retail tariffs	No
Presence of social tariffs	No

Tariffs are published on the DSO website.

3.2. Connection and capacity issues

New end users, or end user who increases their capacity, must pay to DSO a network charge for connection load. This cost depends on consumer groups' connection voltage level (above 35 kV; 1-35 kV; commercial 0.4 kV and households). The amount is determined by the requested connection load times the connection load network charge of the consumer group.

The regulator has adopted the methodology and the model "Calculation of average connection cost factors for connecting consumers to the electricity network", which includes the following principles:

- Postage-stamp method (gross principle) as it applies for determining the network charge for the distribution and transmission network;

- Acquisition price of the network by voltage levels (HV, MV, LV) is taken into account. The utilities' costs are distributed by the voltage levels in the way they are used by the consumers of different voltage level;

- Participation of consumer groups in peak load of the network, which is determined by the calculated capacity and simultaneity factors assessed and acquired from the previous years;

- Forecast of increased capacity bought in the regulatory period.

In accordance with Article 147 of the EA-1, the system operator can refuse the connection to the network, if:

- The prospective user fails to meet the required conditions for connection

- The connection would cause severe disruptions to the power supply, or

- The electricity system operator would incur disproportionate costs due to the connection.

Key issues in the setting of connection charges are set out in the table below.

Table 428: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Deep
	Methodology adopted	Standard and actual cost
Hosting capacity	Scope to refuse connection	Yes
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	No.

4. Distribution system development and operation

4.1. Distribution system development

The distribution system plan is published every other year for a period of 10 years, for all voltage levels up to 110kV. It is approved by the Ministry and notified to the regulator.

The DSO is a state company, so Ministry has own rights to manage the company.

Renewable generation targets are set by the Government. These targets are taken as an input in the distribution development plan.

Overall, the distribution network plan considers:

- The number of newly connected customers;

- The consumption of new customers;

- The replacement of worn-out infrastructure;

- The impact on network losses;

- Achieving the RES and efficient use of energy objectives;

- Economic impacts.

Table 429: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Approved by Ministry, notified to regulator and published
Key responsibilities for its development	DSO
Degree of integration with renewables plan	RES targets explicitly taken into account.
Relationship with consumption trends	Explicitly taken into account, with spatial detail
Relationship with quality of service targets	Explicitly taken into account
How trade-offs between network development and alternative technologies are treated	The network development plan reports only the decisions of the DSOs. The analysis, on which those decisions are based, are not public.
Requirements to integrate cost benefit analysis	

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 430: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	The DSO has no control on embedded generators
Possibility to dispatch flexible loads	No
Other sources of flexibility open to DSO	Control of capacitors in primary substations

Flexible loads are only controlled by the transmission system operator or self-dispatched. The TSO is responsible for balancing the system and reliability of supply by providing through ancillary services. Large customers can participate in balancing the system through the contracts on ancillary services.

DSOs are only in control of capacitors in primary substations.

4.3. Metering

The DSO has full responsibility for metering, and owns the meters.

Beside this, DSO is responsible for all other data management functions (validation, storing, sending the data to parties entitled access to them ...)

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 431: Key approach to metering

Issue	Approach adopted
Discos role in metering	Full responsibility
Monopoly services in the metering	Yes
Smart metering functionality	See text below

The main features of the smart meters installed or planned to be deployed are:

a) quarter-of an hour measurement
b) remote reading
c) remote disconnection/reconnection of customers
d) remote control of the maximum power that can be withdrawn
e) remote operation of appliances at the consumer's premises
a) local port to send real time consumption information to a local screens or computers
f) basic power quality – continuity of supply

Total number of consumers is ca.930,000. Industry and large commercial users (total ca. 15,000) are 100% equipped with smart meters. Households and small commercial users (total ca. 915,000) are 30% equipped with smart meters.

Country Report – Slovenia (gas distribution)

1. Overview of the distribution sector

There are 16 gas DSOs in the territory of Slovenia, all of which are below 100,000 customers. They all belong to the same retailer, under accounting unbundling.

1.1. Institutional structure and responsibilities

Table 432: DSO characteristics

Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 customers	Share of total demand
16	-	-	16	100%

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 433: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Submits proposal	Submits proposal	
Government	Issues primary law	Issues primary law	
NRA	Sets a general act with methodologies, and charges	Sets a general act with methodologies, and charges	Sets a general act with methodologies, and charges

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The system operator submits a request for obtaining approval for the proposed network charge, eligible costs and other elements of the network charge for the regulatory period no later than 4 months before the start of the three-year regulatory period, for which the network charge is being determined. The application shall include:

- A detailed description of the gas DSO services;

- The business plan for the regulatory period;

- data on the planned number of consumption points, leased capacity and distributed volumes by individual consumer groups for the last year of the previous regulatory period and for individual years of the regulatory period;

- Information on the costs of operation;

- Information on the planned investments;

- Data needed to determine the average regulatory asset value for each year of the regulatory period;

- Information on identifiable deviation from the regulatory framework for the previous regulatory period;

- Calculation of the network cost for each year of the regulatory period and for the regulatory period in accordance with the act governing the methodology for calculating the network cost for the gas distribution network;

- Estimation of the financial impact of the network charge on the users of the distribution network, separately for each consumer group.

During the procedure of approval, the Energy Agency assesses the compliance between the determined eligible costs and other elements and the methodology for determining and calculating the allowed network revenue.

If the Energy Agency declines approval of a proposed network charge, 90% of the values from the previous period are taken into account until a new proposal is approved.

Setting out the network charge and determining eligible costs for building and operating the distribution network is specified in the Act laying down the methodology for setting out the network charge and criteria for determining eligible costs for the natural gas transmission network.

For the current regulatory framework (2013–2015) for distribution, the Energy Agency issued several consultation papers and held several public hearings.

1.2. Key figures on revenue and tariffs

The total amount of the distribution allowed revenues in 2013 was 50.82 million EUR, consisting of:

- Distribution: 42.63 million EUR
- Metering: 3.35 million EUR
- Commercial service: 4.84 million EUR.

A breakdown of the number of customers, energy delivered by customer category is set out in the table below. Data about revenue are not available.

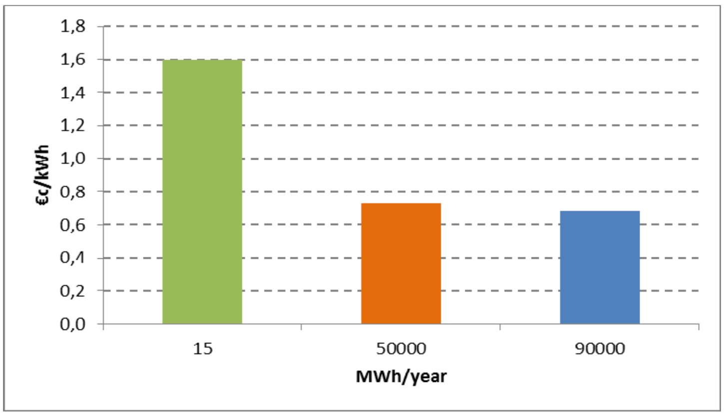
Table 434: Consumption, and number of customers by customer class

C_{Dki}	Upper limit (cubic meters)	Number of customers	Consumption (cubic meters)
C_{DK1}	200	39,739	2,218,617
C_{DK2}	500	14,688	5,787,497
C_{DK3}	1500	45,587	44,216,695
C_{DK4}	2500	19,497	34,073,128
C_{DK5}	4500	8,563	22,036,329
C_{DK6}	10000	2,067	12,784,732
C_{DK7}	30000	1,497	23,947,526
C_{DK8}	70000	637	25,694,981
C_{DK9}	100000	188	17,427,637
C_{DK10}	200000	151	18,585,441
C_{DK11}	500000	100	30,631,017
C_{DK12}	1000000	11	7,808,463
C_{DK13}	5000000	57	26,653,133
C_{DK14}	15000000	19	25,439,547
C_{DK15}	No limit	Less than 5	0

Household customers are usually the customers of category CDK1 - CDK5, but household customers who live in apartment blocks often belong to categories higher than CDK5.

The tariffs that apply to typical customers depend only on yearly consumption. No breakdown is available by consumer classes. The average tariffs per kWh for the main groups of customers and for representative customers, as of 1.1.2013, are illustrated below.

Figure 86: Average network charges for representative consumers



2. Regulation of distribution activities

2.1. General overview

The distribution of natural gas, carried out as a service of a gas distribution system operator (gas DSO), is an optional local service of general economic interest. It can be organised:

- As a public company established by a local community;
- It can be regulated with a concession act between the concessionaire and the local community as the awarding authority; or
- As an investment of public capital into the activity of private law.

The tasks of the gas DSO are listed in the provisions of the EA; these tasks mainly include the following:

- The distribution of natural gas
- The operation, maintenance and development of a distribution network
- The provision of the long-term network capacity.

In 2013, 61 local communities had this service organised with a concession act between the concessionaire and the local community. In 15 local communities, this service was provided by public companies; and in one community as an investment of public capital into the activity of private law. These 77 local communities are served by the 16 DSOs.

In principle, the concessions are tendered for a maximum period of 35 years.

In case of renewal, the company that loses the concession is remunerated on the basis of its concession terms.

Key features of the regulatory regime are set out in the following table.

Table 435: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Concession
Duration of tariff setting regime	3 years
Form of determination	NRA sets the allowed revenue and tariff structure
Scope for appeal regulatory decision	N.A.

2.2. Main incentive properties of the distribution regulatory model

The broad regulatory model is incentive based. In the current regulatory period (2013—2015), the Energy Agency requires the reduction of annual controlled operating and maintenance costs for:

- The planned standard rate of productivity of the economy;
- The individual level of efficiency, which is determined on the comparative analysis of the effectiveness (benchmarking study).

Different X factors in the price cap formula are set for different DSOs.

If the costs of the system operator are lower than actual eligible costs, the DSO may keep the difference.

A "regulatory account" is at work. After every regulatory year, the system operator determines the difference between planned and actual eligible costs of the system operator and the difference between planned and actual financing sources for covering eligible costs. By the methodology of regulated network charges, the system operator is obliged to consider the surplus of the network charge as dedicated revenue for covering the deficit of the previous years or the eligible costs of the following years. At the same time, the system operator has the right to enforce the network charge deficit in establishing the network charge in coming years.

If the Energy Agency establishes that in each year of the regulatory period significant changes in the operation of the system operator occur (i.e. a change in consumption with respect to planned that results in more than 10% impact on the planned total costs), tariffs should are changed to ensure that by the end of current regulatory period the planned and actual revenue are equal.

2.3. Determination of cost of service parameters

The regulatory asset base includes only tangible fixed asset in use and the intangible assets, which constitute a prerequisite for carrying out the activity of the system operator.

The book value of the assets enters the rate base.

The approach to determining key cost of service parameters is summarized in the following table.

Table 436: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue cap
Regulatory asset base	Book value
Capital expenditure	Assessed every year
Approach to operating expenditure	Assessed every year
Form of capital remuneration applied	Real WACC
Additional revenue items (where applicable)	-

The return on assets is evaluated on the basis of the average regulatory asset base, considering pre-tax weighted Average Cost of Capital (WACC).

$$WACC_{pre-tax} = g \cdot r_d + \frac{1}{1-t} \cdot r_e \cdot (1-g)$$

Where:

- ✓ $r_e = r_f + \beta * MRP$ is the cost of equity
- ✓ MRP is the Market Risk Premium
- ✓ R_d is the cost of debt
- ✓ t is tax shield

The debt leverage is set at a target ratio considered as efficient by the regulator. There is no adjustment ex-post.

There is no relation between allowed revenues and quality targets. No system of financial compensation/penalties is implemented

3. Tariffs for distribution services

3.1. Distribution tariffs

Tariffs for the distribution networks are unified for individual customers groups for each geographical areas. Prices for all typical customers in different areas are not the same as the prices reflect different costs of distribution system operators in individual geographical area. Individual customer groups are defined in line with the methodology for charging for the network charge. Distribution system operators determine the tariffs relating to an individual geographical areas, after prior consent of the Energy Agency.

For the identification of consumer groups, see Table 3 above.

All consumers are charged a distribution tariff including max. five components

1. a tariff item for flat rate per month in EUR

2. a tariff item for power per month, in EUR/kW

3. a tariff item for capacity per month, in EUR/(Sm3/day)

4. a tariff item for consumption, in EUR/ Sm3

Smaller consumers (categories CDK1 - CDK5) mainly pay only flat rate (1) and variable part (4). Which items are paid by the individual consumer groups depends on the leased annual capacity or annual consumption.

5. a separate tariff item is paid for metering.

The energy related component of the distribution tariff includes the cost of losses in amount of max. 2%. No other costs are included in distribution tariffs.

Generators are obliged to pay distribution tariff only if they use (demand) energy from the distribution grid. In these cases, DSO charge generators according to the tariff structure for the consumers.

Table 437: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included in distribution tariffs
Presence of uniform tariffs	No
Presence of non-linear tariffs	Yes
Presence of regulated retail tariffs	No
Presence of social tariffs	No

Tariffs are published on the Agency's website.

3.2. Connection and capacity issues

In Slovenia, there are several models for connecting consumers to the natural gas network.

Connection costs depend on the ownership of the connecting pipeline (customer or gas DSO).

1. If the customer is the owner of the pipeline, the connection costs consists of:

- Costs of project document elaboration, monitoring, approvals, and if necessary road closures
- Costs of embedded material
- Costs of machining
- Costs of construction works

2. If the owner of the pipeline is a gas DSO, the customer is charged for:

- Flat-rate connection fee or connection contribution with regard to the provisions of the concession agreement on the implementation of a gas DSO's activities

When building the pipeline, individual gas DSO offers connection free of charge if a consumer binds himself to become its client.

Costs of the connection to the transmission network largely depend on the characteristics of planned consumption (annual leased capacity and planned amount and period of consumption), and scope of work necessary for the construction of the connection pipeline, or the execution of the connection.

If disproportionate costs for connection occur, a consumer can be connected if he covers the disproportionate costs for connection by himself.

When the owner of the connection is a gas DSO, the costs of the connection to the distribution network are determined in accordance with the estimated scope of the use of the connection (in terms of consumption volume), or as specified in the concession contract between the DSO and local community.

For larger consumers, the DSO makes an estimate based on its cost but the client is free to procure the necessary works from a different source.

Table 438: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Shallow in general. Zero to deep charges for larger consumers (depending on the intended scope of use of the connection)
	Methodology adopted	Standard and actual cost
Hosting capacity	Scope to refuse connection	Yes
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	No.

4. Distribution system development and operation

Distribution network is planned and built in accordance with the energy concept of a village or a town, or in line with the commitments set out in the concession contract. When preparing energy concept for the supply of settlements and cities the applicable environmental legislation is taken into account, as well as the achievement of the environmental objectives.

4.1. Distribution system development

In accordance with the new energy legislation the system operator shall prepare an investment plan and submit it to the Energy Agency for the purpose of setting out the regulatory framework. The operator's investment plan shall include a financial evaluation of the investments under the applicable ten-year development plan to be carried out in the subsequent regulatory period. The Energy Agency shall examine and evaluate the investment plan in the procedure for setting out the regulatory framework. In evaluating investment plans and setting the eligible costs of the system operator, the Energy Agency shall not be bound by the value of the investments and their time schedule under the Slovenia’s energy concept, other development plans in the energy sector or the development plans of system operators. If the Agency's evaluation of the investment plans establishes an excessive impact on network charges and if all investments from the investment plan are included in the eligible costs of the system operator, it may take into account only some investments in accordance with the order of priority specified in the investment plan.

In accordance with the provisions of the new Energy Act, the Energy Agency shall establish the methodology for preparing and evaluating the investment plans, which will include:

– The methodological approaches to investment assessment and evaluation;

– The types and mandatory content of investment plans;

– The procedures for preparing and evaluating investment documents and deciding on investments;

– Minimum criteria for determining the efficiency of projects.

The DSO takes into account the deadlines for the preparation of the investment plan and it submission to the Energy Agency for review and evaluation.

Table 439: Approach to distribution planning

<table>
<tr><th>Issue</th><th>Approach</th></tr>
<tr><td>Form of distribution planning document</td><td>Notified to regulator and published</td></tr>
<tr><td>Key responsibilities for its development</td><td>DSO</td></tr>
<tr><td>Degree of integration with renewables plan</td><td>RES targets explicitly taken into account.</td></tr>
<tr><td>Relationship with consumption trends</td><td>Explicitly taken into account, with spatial detail</td></tr>
<tr><td>Relationship with quality of service targets</td><td>Explicitly taken into account</td></tr>
<tr><td>How trade-offs between network development and alternative technologies are treated</td><td rowspan="2">The network development plan reports only the decisions of the DSOs. The analysis, on which those decisions are based, are not public.</td></tr>
<tr><td>Requirements to integrate cost benefit analysis</td></tr>
</table>

4.2. Metering

Metering device may be owned by the gas DSO or the customer.

The DSO is responsible for the collection of data from the meter, and for all other data management functions (validation, storing, sending the data to parties entitled access to them ...).

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 440: Key approach to metering

Issue	Approach adopted
Discos role in metering	Full responsibility
Monopoly services in the metering	Yes
Smart metering functionality	See text below

Out of 132.805 consumers on the distribution network, 46 consumption points are equipped with smart meters, and 651 gas meters deliver a one-way communication for remote data reading. 99.5% of metering points are equipped with a conventional meter.

The deployment of smarts meters is foreseen for the customers with higher consumption and with less predictable demand profile.

Individual DSO can independently decide for wider deployment of smart meters, if it considers that there are great enough benefits, or economically justified reasons, and that the deployment will not increase the recognised costs.

The main features of the smart meters installed or planned to be deployed are:

a) hour measurement
b) remote reading
c) Possibility for innovative tariff schemes
d) Information on current tariff
e) remote disconnection/reconnection of customers
f) remote control of the maximum flow
g) Load profiles registration
h) remote operation of appliances at the consumer's premises
i) local port to send real time consumption information to a local screens or computers
j) Possibility of prepaid mode of work
k) Remote operation of the meter (software update, parameterization and tests)
l) Detection of malicious interventions

Non daily meter customers cover 57% of the consumption of the distribution market. For these customers, different ways are used:

1. Some DSOs read metering devices monthly.

2. Consumers read metering devices monthly, and submit data to DSO.

3. A static load profile model is used to determine monthly consumption of a consumer, but consumption is harmonised with total daily consumption of each distribution network.

Country Report – Slovakia (electricity distribution)

1. Overview of to the distribution sector

In Slovakia operates three exclusives operators of the regional electricity distributions systems, covering the whole territory of the country. These are legally unbundling from the original vertical monopoly. There were are another 160 small DSO in the market with less of 100,000 consumers

1.1. Institutional structure and responsibilities

In Slovakia there are 3 large distributions companies which cover the whole country. In each DSO, the state is a 51% shareholder; however the management control in each DSO is exercised by the owners of the remaining 49% shares.

These large DSO are legally unbundling, the range of action corresponds to the historical regional structure of the country. (West, Central, East).The aim of unbundling was to separate de distribution activities from other electricity activities as generation and electricity supply in order to increase independence of system operators a reduce possible discrimination of system users.

There are another 160 holders of electricity distribution licensed. There are small DSO with less of 100.000 customers, been only functional/Accounting unbundling.

Table 441: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Slovakia	163		3	160	N/A	Not available

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**

The primary responsibility for setting distribution tariffs is spread between the following jurisdictions

- The Government - Ministry of Economy is the main responsible of the energy sector. Ministry of Economy issues the principles in the primary law.

- The NRA (Regulatory Office for Network Industries-RONI) according to Act 250/2012, regulates the electricity and gas sector and distribution activities. They issues methodologies and approves the allowed revenues

- The DSO´s propose the tariff structure

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 442: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges	Regulated services
DSO	Calculates for NRA approval	Calculates for NRA approval	Calculates for NRA approval	NA
Government – Ministry of Economy	Defines main principles	Defines main principles	Defines main principles	NA
NRA	Set methodology and approves(LV)	Set methodology and approves(LV)	Set methodology and approves(LV)	NA

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adapted to setting distribution tariffs involves the following steps:

- Ministry of Economy determines the regulatory principles in primary law.
- DSO proposes the tariff structure and the regulator then approves it.
- Distribution tariff decisions are not subject to public consultation. DSO and NRA (RONI) are the participants in the pricing proceeding.

1.2. Key figures on revenue and tariffs

Distribution revenues in Slovakia in 2013 were € 515,476 million. No further revenue breakdown is available.

A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

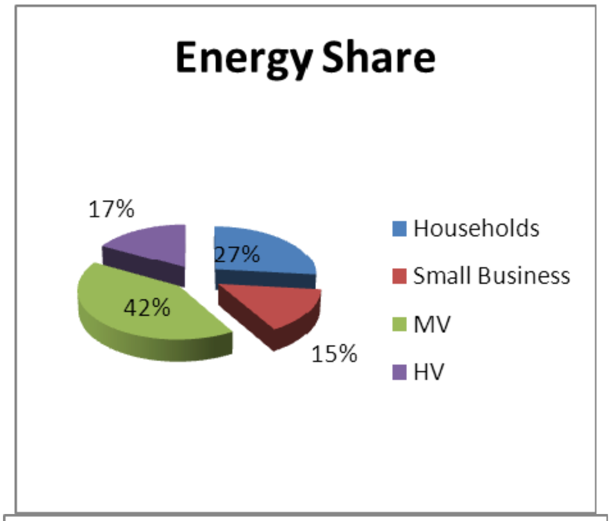
Table 443: Tariff components, customers and revenues per customer class

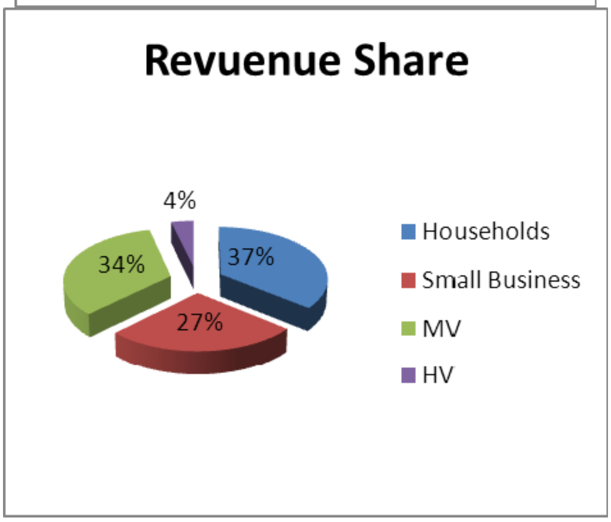
Customer classes	Tariff components	Number of customers	Revenue (Million €)
Household	Capacity charge €/MW(A) Energy charge €/MWh Losses charge €/MWh	2143189	178,457
Small Businesses	Capacity charge €/MW(A) Energy charge €/MWh Losses charge €/MWh	278028	140,467
MV customers	Capacity charge €/MW(A) Energy charge €/MWh Losses charge €/MWh	12944	177,177

HV customers	Capacity charge €/MW(A) Energy charge €/MWh Losses charge €/MWh	96	19,433
Total	-	2434257	515,476

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 87: Proportion of energy and revenue accounted by customer categories





These show a MV and Households as the consumers providing greater revenue shares.

The definition of typical consumer is not used to tariffs analysis. However for the purpose of the National Report CEER, NSR calculates the average yearly consumption of some typical consumers.

The typical network tariff in 2013 for House Hold, small and large industrial customers is illustrated below:

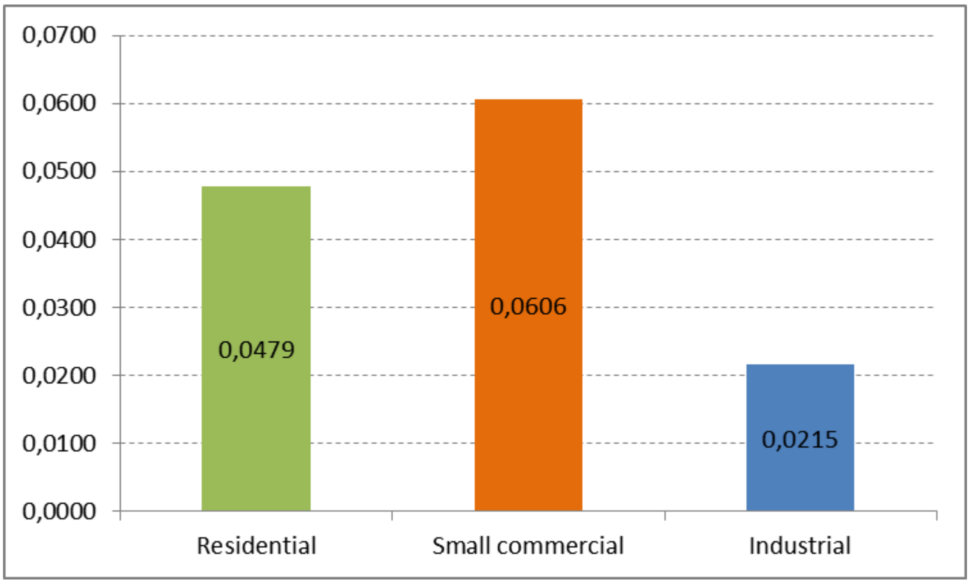
Table 444: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Capacity charges	Energy charges	Total
Residential	3500kWh	58,33	-	109,27	167,60
Small Industrial	50MWh	-	606,37	2423,67	3030,04
Large industrial	24000MWh	-	239097,6	277843,52	516941,12

This network tariff includes electricity transmission (including losses), electricity distribution and electricity distribution losses.

The resulting average tariffs per kWh are illustrated below.

Figure 88: Average network charges (€/kWh), 2013



2. Regulation of distribution activities

The distribution networks operators are regulated under a licence regime. An incentive based price cap model is form of regulation is applied.

2.1. General overview

The roles of the DSO´s in Slovakia are to operate, develop and maintain the distribution network, to ensure a non-discriminatory access to the grid. They are also responsible of facilities a quality customer service.

The Ministry of Economy of Slovakia and the Regulatory Office for Network Industries (RONI) are the competent regulatory authorities to the electric distribution activities. According Act 250/2012, The NRA (RONI) purpose is a transparent no discriminatory manner, the availability of goods and regulated activities related therewith at reasonable prices and in determined quality.

The distribution activities are subject to be authorized by the NRA. The DSO´s are incentivised to reduce cost; a Price CAP methodology of regulation is applied.

The price regulation model covers the whole regulation period which is currently 5 years. The prices are fixed for the regulations period; however prices may be adjusted in some specific circumstances.

Key features of the regulatory regime are set out in the following table

Table 445: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Licence
Duration of tariff setting regime	5 years (2012-2016)
Form of determination (distributor propose/regulator decide)	DSO proposes allowed revenue and tariff structure, NRA approves
Scope for appeal regulatory decision	N.A

2.2. Main incentive properties of the distribution regulatory model

The NRA has defined a model to calculate the maximum price and tariffs for access to the distribution system and electricity distribution. This model is oriented to determine a reasonable profit, necessary to ensure the long-term, safe and efficient operation of the distributions system, a reasonable return on operating assets and stimulate stable. The details of the models included in the Ordinance 221/2013 Coll.

The main aspects of the model are:

- Model is based in Price Cap, when the NRA approves a he maximum price and tariffs for access to the distribution system.
- The price regulation method covers the whole Price regulatory period
- The NRA defines which are the eligible cost and what are not
- The NRA defines the method to calculate a reasonable profit, based in the WACC structure.
- Prices are fixed for the regulatory period, however prices may vary from year with regard to the capital expenditures invested or due to the variable cost changes

There is not mitigation form implemented as correction factor to achieve revenues. DSO´s are incentivized to optimize their costs. DSO may request to NRA to review and adjust prices if the economic parameters which were based the price has been substantially changed. (Ordinance 250/2012 Section 17)

Quality standards have been set by the respective ordinance issued by NRA. They are not interconnected to the tariff system. In Slovakia, a system of automatic compensation payments for failure to comply with the prescribed quality standards is in place.

Automatic compensation is granted to consumers in case some quality standards are not met. The cost of that compensation is not included in the allowed returns of the DSOs.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 446: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Price Cap method
Regulatory asset base	Based on the performed DSO asset assessment in 2006. The RAB Value of 2012 takes in account CAPEX development in the given period and the value of depreciation. During the regulatory period the RAD values do not vary.
Capital expenditure	
Approach to operating expenditure	No benchmark approach
Form of WACC applied	Real WACC, D/E has been set by NRA in the ratio 60/40
Additional revenue items (where applicable)	Not applicable

The following formula is applied in determining the WACC:

$$WACC = \frac{E}{E+D} \times \frac{R_E}{(1-T)} + \frac{D}{E+D} \times R_D$$

Where:

- T: is income tax rate for year t,
- E: is equity in EUR as of Dec 31, 2010,
- D: is debt in EUR as of Dec 31, 2010
- $R_{D:}$ is the real price of debt, calculated average amount of loans given to non-financial companies for the period of 5 and more years with the loan amount more than 1 mil. EUR for the base year at 5,13%,
- $R_{E:}$ is the real price of equity and own funds calculated according to the formula:

$$R_E = R_F + \beta_{LEV} \times (R_M - R_F),$$

Where:

- R_F: is profitability of an risk-free asset, calculated average revenue from 5+ year government bonds issued in the Slovak market between 2007 and 2011 for the base year at 4,01%,
- $(R_M - R_F)$: is the overall risk premium for the base year set by NRA at 3%; for the following years set by RONI between 3% and 6%.
- β_{LEV} is weighted ratio β, which defines the sensitivity of a company share to the market risk, taking into account the income tax rate and the debt share, calculated according to the formula:

$$\beta_{LEV} = \beta_{UNLEV} \times \left[1 + (1 - T) \times \frac{D}{E} \right]$$

Where:

- β_{UNLEV} is the unweight ratio β free of the influence of income tax rate and debt share for the base year at 0,30; for the following years it has been set by NRA between 0,30 and 0,65,
- T is income tax rate for year t
- D/E is the ratio of debt to equity, the base year has been set to 60 % in favour of debt

For the base year, the real ratio of regulatory asset base profitability (WACC) has been calculated by NRA at 6.04%. Parameter values for the following years, which serve to calculate the ratio of regulatory asset base profitability (WACC) before tax, are published on the RONI web site by June 30 of the calendar year.

The regulation formula includes the “X-component”. The so-called “X – factor” has been set in relation to OPEX. OPEX may then be changed through (JPI-X), where JPI is the development of core inflation for the given period. The X-component is selected based on monitoring the company´s performance.

3. Tariffs for distribution services

3.1. Distribution tariffs

The NRA determines the methodology of calculation of distribution tariffs and the tariffs are calculated by each DSO.

DSO´s determined separately for each voltage level the maximum price for access to the distribution system. For each voltage level, the value of the asset used in relation is determined. The level of allowed profit is calculated using the WACC. Allowed profit and operational expenditures represent the amount of allowed revenues for each respective voltage level. These revenues are split 65/35 to fixed and variable part. (Section 26, 27 of Ordinance 221/2013)

The price of access to the distribution system reflects the distribution and transmission, including electricity transmission loses. Also is considered another variable tariff for the losses of the distribution network.

There are four classes of consumers:

- High Voltage
- Medium Voltage
- Low Voltage residential
- Low Voltage another consumers

All consumers are charged a distribution tariff including three components:

- Fixed, Eur per KW charge, based on the contractual maximum power (enforced via the meter)
- Variable Energy, - Eur per KWh, register by metering units
- Variable Distribution Losses, - Eur per KWh distribution losses.

The price decision is published on NRA website and DSO website: http://www.urso.gov.sk

Various other aspects of distribution tariff setting are summarized in the table below.

Table 447: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included in Distributions Tariff
Presence of uniform tariffs	No, each DSO charges different tariff(Corresponding to its allowed revenues)
Presence of non-linear tariffs	No, all tariff components are linear
Presence of regulated retail tariffs	Yes, for Households and Small business with a yearly consumption less than 30 MWh. (End-use price)
Presence of social tariffs	No

The renewable generation and CHP support is funded via an additional tariff component of the distribution tariff. Tariff for the system services including costs of balancing

Embedded generators pay 30% per KW of the installed capacity.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 448: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Half deep fees
	Methodology adopted	The NRA publishes a method to calculate the connection charges.

	Issue	Approach
		Section 42, 44 Ordinance 221/2013
Hosting capacity	Scope to refuse connection	DSO is obliged to connect a consumer, if he meets the connection requirements and has capacity in the network. Generator can be refused, if the connection can jeopardize network´s safety and reliability
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	The price method calculation induces to the DSO to invest in the network development

The methodology use to determine connection cost depends of the consumer class:

For Low Voltage

- For the first year real costs for connection. For next years connection fee for the first year increased by inflation

For Medium Voltage

- Principle post stamp
- Half is paid by consumers and half is paid by DSO's
- Generators pay whole fee and RES pay 0,98 times fee
- Connection costs of previously year divided by capacity connected previously year

For High Voltage

- Real costs of connection
- Half is paid by consumers and half is paid by DSO's
- Generators pay whole fee and RES pay 0,98 times fee

4. Distribution system development and operation

4.1. Distribution system development

Network development plans are not announced to the regulator, so are not published. The Ministry of Economy is responsible for this issue

The key features of distribution system planning are summarized below.

Table 449: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Not applicable
- Key responsibilities for its development	Not applicable
- Degree of integration with renewables plan	Not applicable
- Relationship with consumption trends	Not applicable
- Relationship with quality of service targets	Not applicable
- How trade-offs between network development and alternative technologies are treated	Not applicable
- Requirements to integrate cost benefit analysis	Not applicable

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 450: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	DSO dispatches large embedded generators connected to their networks. Small embedded generators are not dispatched by DSO
Possibility to dispatch flexible loads	Not applicable
Other sources of flexibility open to DSO	Not applicable

4.3. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 451: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs have full responsibility for metering, and own the meters.
Monopoly services in the metering	Yes, for each DSO in its geographic location
Smart metering functionality	Currently test operations of smart meter on selected consumer groups. The smart meters planned to be installed have basic functions. c) quarter-of an hour measurement d) remote reading

As of 2013 there were not smart meters massive installed in Slovakia.

Country Report – Slovakia (Gas distribution)

1. Overview of to the distribution sector

In Slovakia operates one main distributions system operator, covering the whole territory of the country. These are legally unbundling from the original vertical monopoly.

1.1. Institutional structure and responsibilities

In Slovakia there is one main DSO, whose network covers the whole country. There are 39 locals DSO connected to the main DSO, distributing around 19 % of the total volume of natural gas distributed in the country. There is one local DSO (2%) directly connected to the TSO.

In 2013, the total of gas consumption was of 54,79 TWh to around 1,5 million customers.

Summary data on industry structure is set out below

Table 452: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100000 customers	Exemption*	Share of total demand
Slovakia	X		1		N/A	
***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**						

The primary responsibility for setting distribution tariffs is spread between the following jurisdictions

- The Government - Ministry of Economy is the main responsible of the energy sector. Ministry of Economy issues the principles, the scope and method of price regulation is set in the primary law.
- The NRA (Regulatory Office for Network Industries-RONI) regulates the electricity and gas sector and distribution activities. They issues methodologies and approve the allowed revenues, tariff structure and connections charges.
- The DSO calculates the allowed revenue and proposes the tariff structure and connections charges, the NRA approve it after consultation with DSO.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 453: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Calculates for NRA approval	Propose the tariff structure	Calculates for NRA approval
National council	Defines main principles of regulation network industries	Defines main principles of regulation network industries	Defines main principles of regulation network industries
NRA	Set methodology and approves	Set methodology and approves tariff after consultation with DSO.	Set methodology and approves tariff after consultation with DSO.

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adapted to setting distribution tariffs involves the following steps:

- Ministry of Economy determines the regulatory principles in primary law.
- DSO proposes the tariff structure and the regulator then approves it.
- Distribution tariff decisions are not subject to public consultation. The DSO and regulator (RONI) are the participants in the pricing proceeding.

1.2. Key figures on revenue and tariffs

Distribution and metering revenues in The Slovakian Republic in 2013 was € 394 million. No further revenue breakdown is available.

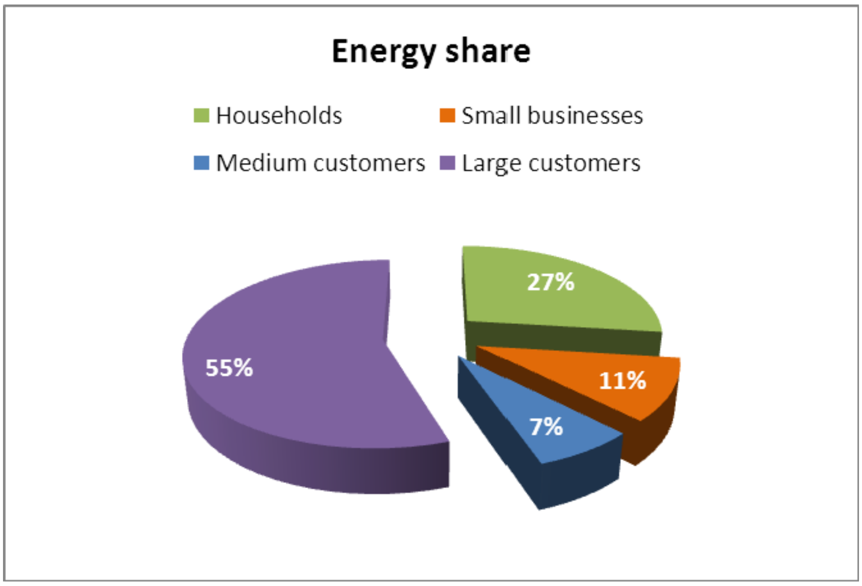
A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

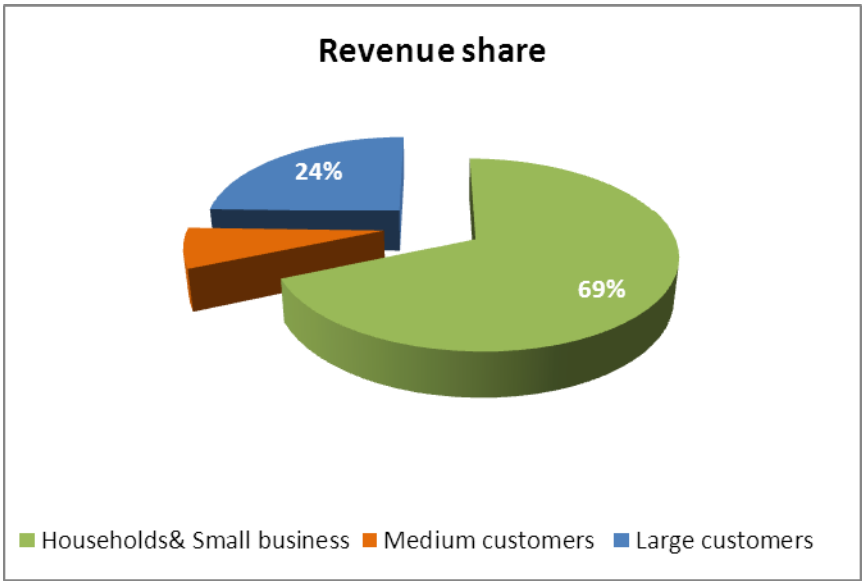
Table 454: Tariff components, customers and revenues per customer class

Customer classes	Tariff components	Number of customers	Revenue (Million €)
Household	Energy component €/m3 Fixed component €/year	1417000	270,284
Small Businesses	Energy component €/m3 Fixed component €/year	75800	
Medium customers	Energy component €/m3 Fixed component €/year Daily maximum component €/(m3/day)/year)	2890	27,196
Large customers	Energy component €/m3 Fixed component €/year Daily maximum component €/(m3/day)/year)	758	96,530
Total	-	1496448	394,000

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 89: Proportion of energy and revenue accounted by customer categories





These show a Households and Small business as the consumer class providing greater revenue shares (69%) according the their energy consumption (38%)

The definition of typical consumer is not used to tariffs analysis. However for the purpose of the National Report CEER, NSR calculates the average yearly consumption of some typical consumers.

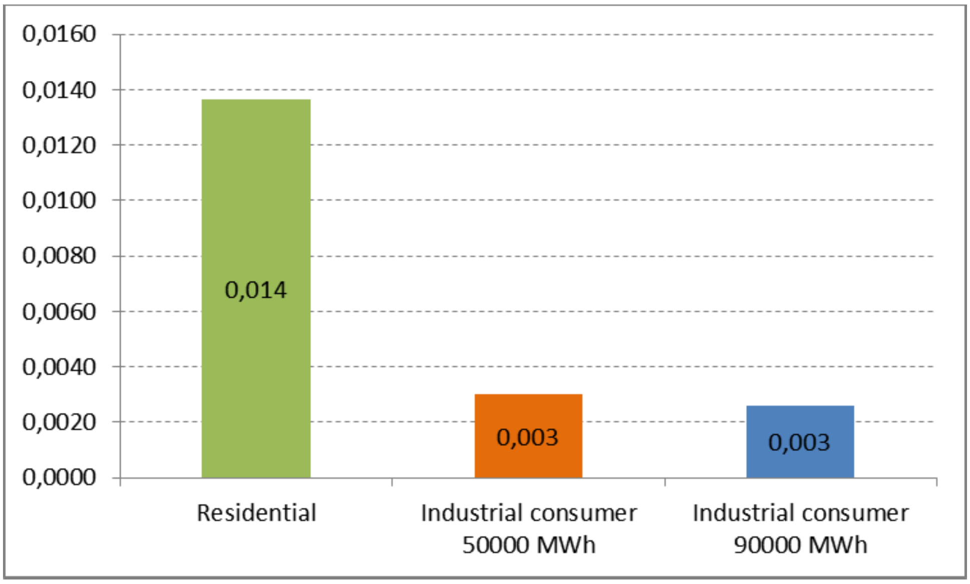
The typical network tariff in 2013 for House Hold, small and large industrial customers is illustrated below:

Table 455: Breakdown of annual charges – typical customer types, 2013 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Total (€)
Households with annual consumption of 15000 kWh	15000 kWh (Household consumption in Slovakia is 19050kWh)	76,2€ (6,35€/month)	138 € 0,0092 €/kWh	214,20
Industrial Consumer with an annual consumption 50000 MWh and 7000 use hours	50MWh	Not available	Not available	150638,49
Industrial Consumer with an annual consumption 90000 MWh and 7000 use hours	90000MWh	Not available	Not available	235033,07

The resulting average tariffs per kWh are illustrated below.

Figure 90: Average network charges (€/kWh), 2013



2. Regulation of distribution activities

The distribution networks operators are regulated under a licence regime. An incentive based price cap model is form of regulation is applied.

2.1. General overview

The role of the DSO in Slovakia is to operate, develop and maintain the distribution network, to ensure a non-discriminatory access to the grid. They are also responsible of facilities a quality customer service.

The Ministry of Economy of Slovak Republic and the Regulatory Office for Network Industries (RONI) are the competent regulatory authorities to the gas distribution activities. According Act 250/2012, The NRA (RONI) purpose is a transparent no discriminatory manner, the availability of goods and regulated activities related therewith at reasonable prices and in determined quality.

A Price CAP methodology of regulation is applied. The price regulation model covers the whole regulation period which is currently 5 years. The Prices are fixed for the regulations period; it incentivised DSO to reduce costs.

DSO may request the regulator to adjust tariffs if the economic parameters on whose basis the price was set have been substantially changed. For example in case of change of gas price to make up for losses of profit and own consumption of DSO.

There is no correction factor implemented to achieve revenues.

Key features of the regulatory regime are set out in the following table

Table 456: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Licence
Duration of tariff setting regime	5 years
Form of determination (distributor propose/regulator decide)	DSO proposes allowed revenue and tariff structure, NRA approves
Scope for appeal regulatory decision	N.A

2.2. Main incentive properties of the distribution regulatory model

The NRA has defined a model to calculate the maximum price and tariffs for access to the distribution system. This model is oriented to determine a reasonable profit, necessary to ensure the long-term, safe and efficient operation of the distributions system, a reasonable return on operating assets and stimulate stable. The details of the models included in the Ordinance 193/2013 Coll.

The main aspects of the model are:

- Model is based in Price Cap, when the NRA approves a he maximum price and tariffs for access to the distribution system.
- The price regulation method covers the whole Price regulatory period
- The NRA defines which are the eligible cost and what are not
- The NRA defines the method to calculate a reasonable profit, based in the WACC structure.

- Prices are fixed for the regulatory period, however prices may vary from year with regard to the capital expenditures invested or due to the variable cost changes

There is not mitigation form implemented as correction factor to achieve revenues. DSO´s are incentivized to optimize their costs. DSO may request to NRA to review and adjust prices if the economic parameters which were based the price has been substantially changed. (Ordinance 250/2012 Section 17)

Quality standards have been set by the respective ordinance issued by NRA. They are not interconnected to the tariff system. In the Slovakia Republic, a system of automatic compensation payments for failure to comply with the prescribed quality standards is in place.

Automatic compensation is granted to consumers in case some quality standards are not met. The cost of that compensation is not included in the allowed returns of the DSOs.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 457: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Price Cap method
Regulatory asset base	Based on the performed DSO asset assessment in 2006. The RAB Value of 2012 takes in account CAPEX development in the given period and the value of depreciation. During the regulatory period the RAB values do not vary.
Capital expenditure	
Approach to operating expenditure	No benchmark approach
Form of WACC applied	Real WACC, D/E has been set by NRA in the ratio 60/40
Additional revenue items (where applicable)	Not applicable

The following formula is applied in determining the WACC:

$$WACC = \frac{E}{E+D} \times \frac{R_E}{(1-T)} + \frac{D}{E+D} \times R_D$$

Where:

- *T*: is income tax rate for year t,
- E: is equity in EUR as of Dec 31, 2010,
- *D*: is debt in EUR as of Dec 31, 2010
- $R_{D:}$ is the real price of debt, calculated average amount of loans given to non-financial companies for the period of 5 and more years with the loan amount more than 1 mil. EUR for the base year at 5.13%,
- $R_{E:}$ is the real price of equity and own funds calculated according to the formula:

$$R_E = R_F + \beta_{LEV} \times (R_M - R_F),$$

Where:

- R_F: is profitability of an risk-free asset, calculated average revenue from 5+ year government bonds issued in the Slovak market between 2007 and 2011 for the base year at 4.01%,
- $(R_M - R_F)$: is the overall risk premium for the base year set by NRA at 3%; for the following years set by RONI between 3% and 6%.
- β_{LEV} is weighted ratio β, which defines the sensitivity of a company share to the market risk, taking into account the income tax rate and the debt share, calculated according to the formula:

$$\beta_{LEV} = \beta_{UNLEV} \times \left[1 + (1 - T) \times \frac{D}{E}\right]$$

Where:

- β_{UNLEV} is the unweight ratio β free of the influence of income tax rate and debt share for the base year at 0,30; for the following years it has been set by NRA between 0,30 and 0,65,
- T is income tax rate for year t
- D/E is the ratio of debt to equity, the base year has been set to 60 % in favour of debt

For the base year, the real ratio of regulatory asset base profitability (WACC) has been calculated by NRA at 6.04%. Parameter values for the following years, which serve to calculate the ratio of regulatory asset base profitability (WACC) before tax, are published on the RONI web site by June 30 of the calendar year.

The regulation formula includes the "X-component". The so-called "X – factor" has been set in relation to OPEX. OPEX may then be changed through (JPI-X), where JPI is the development of core inflation for the given period. The X-component is selected based on monitoring the company´s performance.

3. Tariffs for distribution services

3.1. Distribution tariffs

The NRA determines or approves the methodology of calculation of tariffs and setting tariffs.

According to the Ordinance of the Office laying down the price regulation in gas industry maximum 60 % distribution costs comprise fixed amount (capacity component).

All of the costs are taken from the individual cost centres. Each cost centre is afterwards reallocated to the respective sales groups based on the best suitable allocation keys (actual usage of cost centre by the sale group - e.g. number of customers, gas volumes sold, gas daily maximum). The amount of expected revenues should cover the total costs of the sale group. The legislation rules set the forbiddance of the cross donations of the sale groups.

The tariff system is not divided based on pressure levels, but tariffs are split based on expected annual distributed gas volume. There is not time of use differentiation tariffs.

There are two classes of consumers:

- Residential
- Industrial (small businesses, medium customers, large customers)

The tariff components of each class of consumers is detail in table 3 of section 1.2

The price decision is published on NRA website and DSO website (Slovakian Only):

- http://www.urso.gov.sk
- http://www.spp-distribucia.sk/sk_obchodno-technicke-informacie/sk_cenniky

Various other aspects of distribution tariff setting are summarized in the table below.

Table 458: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included in Distributions Tariff. The energy related component of the distribution tariff includes the cost of losses (2 %).
Presence of uniform tariffs	Yes, the same tariff for consumers everywhere in the country (post stamp principle)
Presence of non-linear tariffs	No, all tariff components are linear
Presence of regulated retail tariffs	**Yes** End user price regulation for Households and with a yearly consumption less than 68.575 MWh and for small businesses with yearly consumption less than 100 MWh.
Presence of social tariffs	No

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 459: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Shallow
	Methodology adopted	The NRA approved the connection charges. There are Maximum prices for connecting to the distribution system: - For household consumers - For non-household consumers
Hosting capacity	Scope to refuse connection	DSO is obliged to connect a consumer. DSO is allowed refuse connection of consumers only if the technical and commercial conditions for connection to the network are not met.
	Requirements to publish hosting capacity	No
	Targets and/or incentive schemes to enhance hosting capacity	No specific measures, but DSOs are obliged to ensure they have sufficient capacity on the network.

4. Distribution system development and operation

4.1. Distribution system development

Distributions system development plan is not approved, but it is published by the regulator. Distribution development plan network consists only of brief information about the numerical expansion of the distribution network.

The key features of distribution system planning are summarized below.

Table 460: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Published but not approved by the regulator.
- Key responsibilities for its development	DSO
- Degree of integration with renewables plan	Not defined in network plan.
- Relationship with consumption trends	Not applicable
- Relationship with quality of service targets	Not defined in network plan
- How trade-offs between network development and alternative technologies are treated	Not defined in network plan
- Requirements to integrate cost benefit analysis	Not defined in network plan

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 461: Key approach to metering

Issue	Approach adopted
Discos role in metering	DSOs have full responsibility for metering, and own the meters.
Monopoly services in the metering	Yes
Smart metering functionality	Smart meters are currently standardly placed in the offtake category above 60 000 m3/year. Currently 4800 smart meters are placed. The smart meters provides the following information: e) remote reading f) max/min hourly flow (customers with consumption above 400 000 m3/year), g) Daily consumption.

Country Report – Great Britain electricity distribution

1. Overview of the distribution sector

There are 14 main DNOs of which 6 are part of vertically integrated entities

The regulator, Ofgem determines allowed revenue, while the DNO sets tariffs and connection charges, subject to Ofgem approving its charging methodology

Revenue and tariff setting is exclusively the role of the DNO and Ofgem

1.1. Institutional structure and responsibilities

In Great Britain there are 14 main Distribution Network Operators (DNOs) supplying electricity to around 30 million customers covering an area of 229.848 km^2. Summary data on industry structure is set out below.

Table 462: DSO characteristics

	Total number DNOs	Ownership unbundled	Legally unbundled	DNOs with less than 100,000 customers	Exemption*	Share of total demand
Great Britain	14 major and 8 independent	6 are part of vertically integrated entities	All	6	Independent DNOs have to comply with the same unbundling requirements	0.5%

Every DNO licence is held by a company – that is, a distinct legal entity within any wider corporate or ownership group. Licence conditions require compliance with the requirements in the respective Internal Market Directives, and permit six DSOs to remain in vertically integrated groups. The same requirements are in place for the smaller independent DSOs.

The responsibility for setting distribution tariffs is shared between the NRA (Ofgem) and the DNO. The definition of allowed revenue is determined solely by Ofgem. The DNO proposes the tariff structure and Ofgem takes a decision, following consultation with relevant stakeholders.

The DNO will also propose a methodology to calculate its connection charges. Ofgem will assess this methodology and following consultation with stakeholders take a decision on it. Note that Ofgem does not approve the actual connection charges, only the principles in the methodology.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below. The setting of revenues and tariffs is solely the responsibility of Ofgem and the DNOs

Table 463: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Proposes revenues to NRA	Proposes tariff structure to NRA	Calculates methodology for NRA approval
Government	Not involved	Not involved	Not involved
NRA	Takes decision on allowed revenues	Takes decision on tariff structure based on DSO proposal	Approves principles in the methodology and not charges

Any change to the tariff methodology is first developed by industry (DNOs, suppliers and generators) as part of a working group. The working group will consult on the proposal and take account of wider industry views. The proposal can then be submitted to Ofgem for a decision. Ofgem can chose to consult on the proposal or move directly to taking a decision. Once a decision is made, the new methodology can only become effective at 2 points in the year (1 April or 1 October). Industry must have 3 months warning of these changes prior to implementation.

1.2. Key figures on revenue and tariffs

Net distribution revenues in Great Britain in 2013 for the 14 DNOs were £5,824 billion (€7,250 billion). In addition the DNO received £54 million (€67.3 million) from metering activities.

Customers are defined by voltage (LV, HV, EHV) and metering arrangements (half hourly, non-half hourly). Non half-hourly customers are further split by settlement profile class. Customers pay a fixed charge and a variable charge based on consumption (some customer types pay time-of-use), which customers with half hourly meters also pay capacity and reactive charges

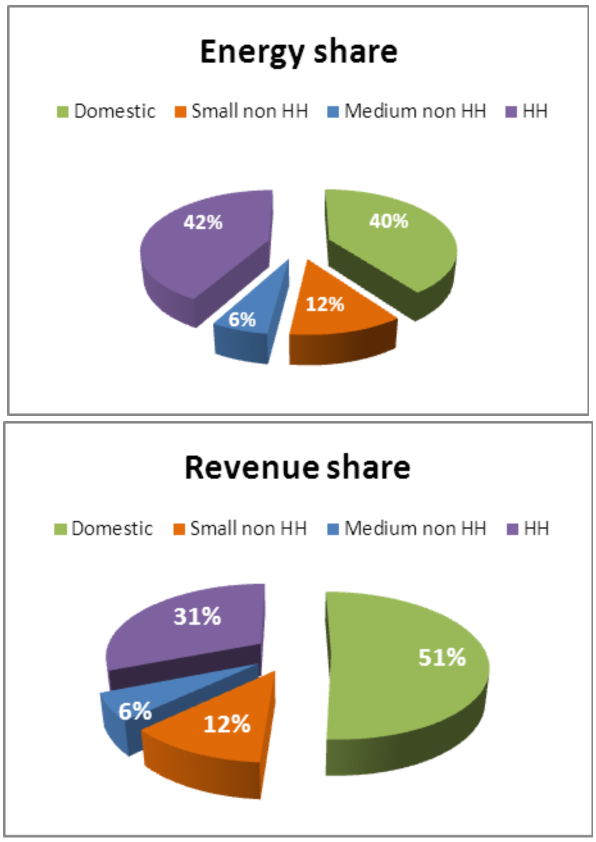
A breakdown of revenue by customer category, including information on available tariff components and the number of customers in each category is set out in the table below.

Table 464: Tariff components, customers and revenues per customer class, 2013

Customer classes	Tariff components	Number of customers	Revenue (£)
Domestic	KWh, per-day standing charge	27.483.911	2.997.013.626
Smaller non-domestic	KWh, per-day standing charge	2.123.382	691.413.232
Medium non-domestic	KWh, per-day standing charge	161.544	321.699.418
Half hourly metered customers	KWh, KW, KVA	138.397	1.814.087.793
Total	-	29.907.216	5.824.214.069

The breakdown of energy volumes and distribution revenue by customer category are set out in the charts below.

Figure 91: Proportion of energy and revenue accounted by customer categories



The above figure show a disproportionate share of revenue borne by domestic customer categories in relation to the respective energy shares. However, the above graph does not adjust for the respective cost of service provision by category and customer specific costs.

A typical network tariff for one of the GB distribution companies in 2014 has been calculated below for the following classes of customers:

- Residential – domestic unrestricted (non-half hourly)
- Small commercial – low voltage medium non-domestic (two rate, non half-hourly)
- Industrial – high voltage half hourly meter

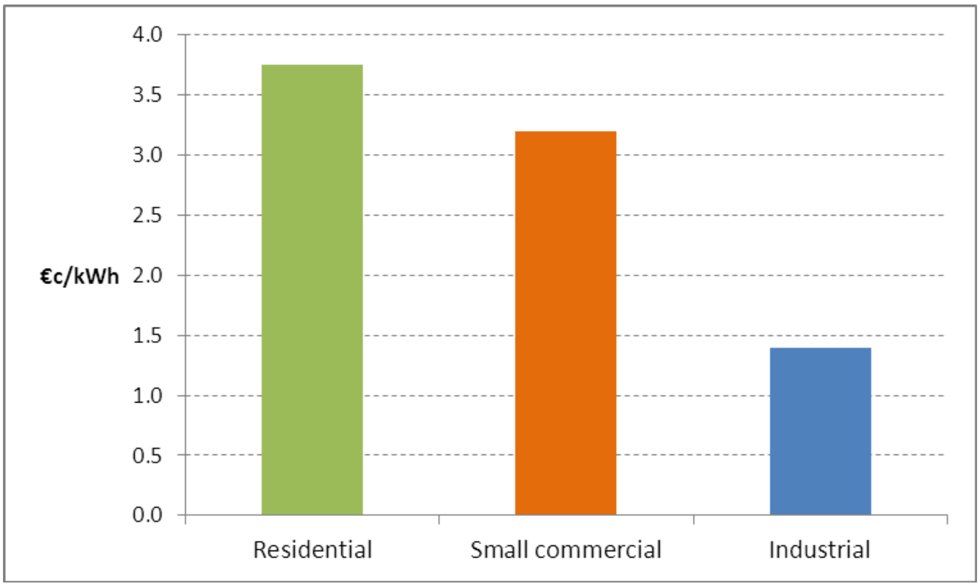
Table 465: Breakdown of annual charges – typical customer types, 2014 (€)

Customer type	Notional Energy usage	Fixed charges	Energy charges	Demand and reactive charges	Total
Residential	3500kWh	18	114		132
Small commercial	50MWh	140	1.467		1.607
Industrial	24000MWh	303	253.258	81.934	335.495

Note: Estimated from data from the CDCM of South Eastern Power Networks for 2014-15

The resulting average tariffs per kWh are illustrated below.

Figure 92: Average network charges (€cents/kWh), 2013



The distribution tariff for half-hourly metered customers is dependent upon the point of network at which they are connected. Small industrial customers are typically connected at low voltage (up to 6.6kV), largely industrial customers are most likely to be connected at high voltage (above 6.6kV), while customers connected at 11kV or above (extra high voltage) are charged in accordance with a different methodology that has site-specific properties and charges based on long-term incremental cost. This is called the ´extra high voltage distribution charging methodology´, called the EDCM. This model includes customer specific information and so is not publicly-available.

The charging methodology is based upon allocating the costs of an incremental increase in demand of 500MW. These costs are allocated to customer types based on that customer type’s contribution to peak network demand. The price signal generated by the methodology is then scaled up or down based on a p/kWh scaling amount so that tariffs allow DSOs to recover its allowed revenue under the price control.

2. Regulation of distribution activities

Regulatory revenues are set under an approach (RIIO) designed to incorporate allowance for incentives, innovation and outputs. An 8 year regime is in place with specific focus on minimising total expenditure (capital and opex). Sharing mechanisms for over and under spend are in place.

2.1. General overview

The approach to regulating distribution charges is termed RIIO (Revenues = incentives + innovation + outputs). This approach replaced the previous RPI-X approach and is designed to focus to what the network company should deliver over the price control period. The output categories are:

- Reliability and availability
- Safety
- Customer satisfaction
- Timely connections
- Environmental impact
- Social

Rewards and penalties for performance against these categories is subject to a mix of financial and reputational incentives.

Revenues are set every 8 years as part of a price control process. Penalties or rewards from incentive schemes automatically update these revenues (on a 2 year lag). Distribution allowances are set ex ante by Ofgem as part of the price control. Business plans are submitted, following extensive stakeholder engagement, to Ofgem to inform the price control setting process.

The price control allows for some re-opener mechanisms – for example, investment schemes in cases where uncertainty existed at the time of setting the price control.

The application of a simple x factor is not applicable in RIIO price controls.

There are no concession schemes in place. However, there is competition for new connections between incumbent DSOs, independent DSOs and independent connection providers. Independent DSOs also compete with DSOs to adopt new connection assets and operate and maintain them.

Summary features of the regulatory regime are set out in the following table

Table 466: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	Licence
Duration of tariff setting regime	8 years
Form of determination (distributor propose/regulator decide)	Distributor propose, regulatory decide
Scope for appeal regulatory decision	Merits appeal to the Competition Commission permitted

2.2. Main incentive properties of the distribution regulatory model

A key pillar of the regulatory framework is the use of a revenue control period of 8 years, which is set using a RIIO approach (Revenues = Incentives + Innovation + Outputs). This is an incentive based approach involving:

- Setting total expenditure (Totex) allowances;
- Including Totex Incentive Mechanisms; and
- Including an additional range of incentive adjustments in the allowed revenue formula, including for quality of service.

The following risk mitigation on profit sharing is in place:

- Under the Totex Incentive Mechanisms there is a sharing mechanism for over spend/ under spend by a company. Under the sharing mechanism, the DNO retains a fixed percentage (around 60%) of any profit with the customers receiving the remainder (around 40%). The same proportions apply to any over spend.
- Analysis of the financial viability of the DSO at the price control review
- The use of Uncertainty Mechanisms – for example related to expenditure requirements.

The DSO's revenue is adjusted for a quality of service component that takes into account performance against the following indicators:

- Number of Customer interruptions;
- Duration of Customer interruptions;
- Community satisfaction;
- Speed and quality of telephony response;
- Ofgem's Customer Service Reward Scheme;
- Supply restoration under severe weather conditions;
- Supply restoration under normal weather conditions.

DSO's are required to come within 97% and 103% of revenue by managing charges. Over/under recovery is then reflected in a "correction factor" term in the allowed revenue formula. Penalty interest is applied to excessive over or under recovery.

2.3. Determination of cost of service parameters

In determining the revenue requirement Ofgem considers comparative efficiency analysis, regional factors, an information quality incentive (IQI) and total cost requirements. A toolkit approach is adopted that applies a combination of aggregated and disaggregated econometric and engineering based approaches, totex and disaggregated data as well as using historical and network company forecast data.

A key objective of the determination of a revenue requirement is to reduce total costs, with total expenditure/aggregated models developed to identify the DSO's opex-capex trade-offs. In addition, disaggregated econometric and engineering/activity based approaches are developed to enable the estimation of the relationship between a disaggregated cost and a given cost driver. An efficient total expenditure allowance is determined based on an average of the different approaches. A mix of approaches is adopted to reflect Ofgem's belief that there is no one correct model for assessing comparative efficiency but a number of plausible ones.

The information quality incentive (IQI) matrix provides incentives for network companies to reveal their efficient level of costs by providing a reward (or penalty) according to their cost submission relative to Ofgem's assessment. The mechanism also sets the efficiency incentive rate which sets out the proportion of underspend (or overspend) during the price control period incurred by shareholders.

The approach to determining key cost of service parameters are summarized in the following table.

Table 467: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue based with efficiency adjustments
Regulatory asset base (RAB)	Efficient investment is rolled forward into the RAB, with typically 85% of total expenditure assumed to be capital related
Capital expenditure	Total expenditure benchmarking
Approach to operating expenditure	Total expenditure benchmarking
Form of WACC applied	Vanilla WACC, with tax modelling in the cashflow
Additional revenue items (where applicable)	IQI incentives, service quality

The capitalised proportion of Totex – typically 85%, is incorporated into the RAB, with depreciation and inflation indexation applied to the RAB balance at the end of the year. Ofgem retains the right to challenge/ disallow inefficient expenditure and adjustments made to the RAB, however, it informs that owing to business plan assessment and annual reporting scrutiny, there have been few incidents of disallowances.

Ofgem's approach to the cost of capital is to apply the Vanilla Weighted Average Cost of Capital (WACC). Under this approach the DSO's tax cost is separately calculated as a discrete cash flow allowance. A real vanilla WACC is applied because the regulatory asset base is indexed. The WACC incorporates notional gearing of 65%, which is broadly reflective of business gearing levels (52.1% to 71.2%).

3. Tariffs for distribution services

The tariff methodology permits the setting of negative energy charges (in the event of export) for embedded generators

Tariffs vary by DNO with different methods in place for extra HV customers (negotiated) and other customers

Connection charges reflect the cost of work involved, and are predominately shallow in nature

3.1. Distribution tariffs

Two use of system charging methodologies are in place. One for extra high voltage customers (EDCM) and another covering all other customers connected (CDCM).

The EDCM charges on a site specific way with forward investment costs included. The CDCM differentiates charges by voltage connection and customer type/usage. For LV and HV customers, costs are categorised as:

- Network asset by voltage and transformation level: 132kV; 132kV/EHV; EHV; EHV/HV; 132/HV; HV; HV/LV; LV circuit
- Transmission exit charges; and
- Other expenditure split between being allocated: by network level; and to assets dedicated to one customer.

There are a number of different tariff classes but the main four types are:

- Domestic, with the following components:
  - One or two rate (per KWh)
  - Fixed charge (per day)
- NHH metered (non-domestic), with the following components:
  - One or two rate (per KWh)
  - Fixed charge (per day)
- HH metered (LV, HV and HV substation), with the following components:
  - Three rate (per KWh)
  - Fixed charge (per day)
  - Capacity charge (per day)
  - Reactive charge (per KVArh)
- EHV HH metered, with the following components:
  - Super-red rate (per KWh)
  - Fixed charge (per day)
  - Capacity charge (per day)
  - Exceeded capacity charge (per day)

In the case of embedded generators, where a DNO considers that an embedded generator is providing a benefit to the network, the per-KWh network charges are negative (a credit). Depending on the type of generator (e.g. intermittent), that generator may pay fixed and reactive charges.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 468: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	These are covered by the supplier
Presence of uniform tariffs	No – these vary by DNO
Presence of non-linear tariffs	All tariff components are linear
Presence of regulated retail tariffs	No
Presence of social tariffs	No

Suppliers pay the cost of losses on the network. DSOs include a loss adjustment factor for each network level. This informs the supplier how much additional electricity it needs to purchase to cover that which will be lost in transportation.

3.2. Connection charges

Key issues in the setting of connection charges are summarised in the table below.

Table 469: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Charges are considered bespoke and based on the cost of the work. These are relatively shallow in nature (´shallow-ish´)
	Methodology adopted	The DNO must publish a methodology that is to be approved by the regulator.
Hosting capacity	Scope to refuse connection	The DNO is required by the Act to connect those that require connection
	Requirements to publish hosting capacity	Hosting capacity is published in the annual Long Term Development Statement (LTDS)
	Targets and/or incentive schemes to enhance hosting capacity	No specific targets are set. However, there are incentives such as the Load Index and the Interruption Incentive Scheme that provide incentives to invest in capacity

For most connections, charges are bespoke and based on the cost of the work required. The costs are computed by the DSO. For certain tasks, such as scheme design approval and inspection and monitoring of works, set fees apply.

Connection charges are predominately shallow in nature. Customers pay the full cost for assets that will only be used by them or are not part of the minimum cost scheme for connection. Customers will also pay a proportion of wider network reinforcement cost where required. The proportion of wider reinforcement that they pay for is determined by the amount of the created capacity that they use. Customers pay for reinforcement at the voltage level they have connected at, plus reinforcement at one voltage level higher. For example, if a customer connects to the 11kV network, they will pay charges for reinforcement works on the 11kV and 33kV networks.

For distributed generation connections, the high cost project threshold applies. Any reinforcement costs above £200/kW will be paid by the connecting customer.

DNOs are required to maintain and publish a connection charging methodology which details how connection charges are calculated. Certain sections of the methodology are common across distribution service areas but charges are specific to each DNO. The regulator does not approve charges but does approve the methodology. Non-contestable work must be charged ‘at cost’ to the customer. Margins are permitted on contestable work where the DNO has to compete with other parties).

Section 16 of the Electricity Act 1989 places a duty on the DNO to connect those requiring a connection. It also lists the relevant parties that can request a connection as being the owner or occupier of a premises or the authorised supplier operating on their behalf. A DSO is required to issue a quote for the connection works within 3 months. The connecting customer must then decide if it wants to go ahead with the work.

DNOs are required to publish hosting capacity through the long term development statement. This statement contains details of parts of the DNO's network that will reach capacity within five years (e.g. thermal capacity, voltage capacity etc.) and the DNO's plans to improve capacity in the next two years. The statement is updated twice a year.

Ofgem has introduced incentives for DNOs to improve information provision to connecting customers. In response some DNOs publish 'heat maps' which show hosting capacity down to the 11kV network.

No specific targets for hosting capacity are set. There are however incentives, such as the Load Index and the Interruption Incentive Scheme which encourage DNOs to invest in an efficient and reliable distribution system. The Load Index is an output metric for substation loading capturing a the loading risk on a substation taking account of load (MVA) over firm, duration over firm and forecast load growth. The Interruption Incentive Scheme sets targets for each DNO's performance in provision of a reliable service. DNOs are rewarded or penalised depending on their performance on the number and duration of interruptions.

4. Distribution system development and operation

Each DNO publishes a 5 year Long Term Development Statement (LTDS), which is published annually with a mid-year update

The DNOs can enter into bilateral arrangements with Demand and Embedded Generators for dispatch

The role of the DNO in metering is largely restricted to maintenance of meters installed prior to March 2007.

There are currently more than 750,000 smart and advanced meters installed. A further 26.3 million smart meters are planned to be installed by the end of 2020

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 470: Approach to distribution planning

Issue	Approach
Form of distribution planning document	Each DNO is required to publish a LTDS that looks 5 years ahead. This is published annually with a mid-year update. It provides network data from the highest distribution voltage down to the lower voltage busbars of primary substations (typically 11kV)
- Key responsibilities for its development	Plan is prepared by the DNO subject to an agreed scope
- Degree of integration with renewables plan	No direct relationship
- Relationship with consumption trends	The plan takes into account forecast demand growth over the 5 year period
- Relationship with quality of service targets	The DNO is responsible for ensuring the network is developed consistent with the planning standard embedded in its licence and to meet its quality of service targets
- How trade-offs between network development and alternative technologies are treated	The LTDS does not address this. However, the DNOs have to justify proposed investment decisions and address trade-offs in its business plan price control submissions each 8 years
- Requirements to integrate cost benefit analysis	Cost benefit analysis is integrated into the business plan submissions at the 8 yearly price control review.

4.2. Distribution system operations

The key features of distribution system operations are summarized below.

Table 471: Approach to distribution planning

Issue	Approach
Requirements for dispatch of renewable plants connected to DSO network	A DNO can enter into a bilateral arrangement with a generator connected to its network so that the DSO can issue dispatch instructions
Possibility to dispatch flexible loads	A DNO can enter into bilateral agreements with a demand or generation customer
Other sources of flexibility open to DSO	Trials related to use of storage are being undertaken

Generators in Great Britain self-despatch. However, a DNO can enter into a bilateral agreement with a generator connected to its network so that the DNO can issue despatch instructions provided that such arrangements are consistent with any operational obligations to the system operator. In addition, a DNO can enter a bilateral agreement with a demand or generation customer connected to its network to modify its load at the instruction of the DNO.

A number of trials are underway where a DNO has access to battery storage. Future arrangements for the use of storage are under development.

4.3. Metering

Key issues regarding metering, and the role of the DNOs, are summarised in the following table.

Table 472: Key approach to metering

Issue	Approach adopted
Discos role in metering	DNOs only have obligations to maintain meters installed prior to 31 March 2007.
Monopoly services in the metering	Since 31 March 2007 the market has been liberalised, responsibility is generally on the suppliers
Smart metering functionality	Half hourly measurement Remote reading Remote disconnection Remote control of maximum power Meters are capable of receiving tariff information and passing it on to appliances that can be programmed to react in a particular way Local port to send real time information to consumers

The market for meters was liberated at the end of March 2007. DNOs have legacy obligations to provide (and operate) electricity meters installed prior to 31 March 2007, which are subject to separate price control arrangements. Subsequently the responsibility is largely on the suppliers. Suppliers can source metering services from alternative suppliers or the DNOs. DNOs do not have to offer any services but are under an obligation to report damage or interference of the metering equipment. However, some DNOs continue to offer meter assets provision services for traditional electricity meters.

While it is not expected that DNOs will directly provide smart metering meter assets provision services, it is possible that parent companies may operate in the smart metering market.

As of Q1 2014 there were more than 760,000 smart and advanced meters installed in Great Britain, broken down as follows.

Table 473: Number of smart meters installed – by end of 2013

Customer category	Number
Smart meter – domestic	234,336
Smart meter – non domestic	5,711
Advanced meter – non domestic	521,875
Total	761,922

Note: Advanced meters have a minimum requirement to store half hourly data to which the customer can have timely access and the supplier remote access. These are to be replaced by smart meters by 2020.

The GB Government coordinates and approves the Smart Meter deployment plan. The following roll out plan for smart meters is in place. This involves the installation of more than 26.3 million smart meters by the end of 2020.

Table 474: GB Government Smart Metering roll out plan.

Year	Domestic	Non-domestic
2014	488,220	120,396
2015	1,508,308	188,528
2016	3,219,830	213,879
2017	5,049,894	326,095
2018	5,678,206	341,320
2019	5,431,616	320,212
2020	3,910,045	284,314

4.4. Annex 1 – The RIIO Regulatory Price Control Framework

This section considers the RIIO regulatory framework. In particular, the various incentive mechanisms and innovation drivers are discussed and quantified.

4.4.1. Introduction

Since 2013 a new incentive regulation for natural gas DSOs has been in use, known as RIIO (Revenue = Incentives + Innovation + Outputs). For electricity DSOs, RIIO regulation is planned to be introduced in April 2015. The RIIO approach maintains certain central aspects of the previously-used approach (and in particular, continued use of strong efficiency incentives, or rewards for spending less than planned). Importantly, RIIO also uses measures which encourage network companies to focus on the outputs for their customers; contribute to the development of a low carbon economy and innovate to reduce network costs. Some of the most notable characteristics of RIIO include:

- 8-year regulatory period (previously, a 5-year period was used);
- Upfront (ex-ante) assessment to set base revenues and the basis for change in revenues;
- Cost-sharing mechanism (i.e. cost savings are shared between the company and customers);
- Totex approach (takes opex and capex together, thereby incentivising the company to opt for the most economic option when deciding between opex and capex solutions);
- Comprehensive quality outputs (e.g. network reliability level, emissions levels, availability);
- Uncertainty mechanisms (provisions available to manage specific cases of uncertainty risk through possible revenue changes during the regulatory period);
- Promotion of innovation (encourages DSOs to consider different ways of achieving greater cost savings or increase the scope of future delivery).[127] Innovation is promoted in various ways, as discussed in Box 1.

Box 1. Promoting innovation under RIIO

The RIIO regulatory framework is designed with a view to promoting innovation in various ways. The use of an 8-year price control is meant to offer DSOs greater certainty of the rewards for successful innovation. The NRA also takes into consideration past and future innovation funding provided to DSOs when setting the efficiency frontier for the regulatory period (higher levels of innovation funding suggest innovation should be achieved more cost-efficiently). Furthermore, three financial stimuli are used to promote innovation:

1. **Network innovation allowance** – an allowance which each DSO receives to fund small-scale innovative projects as part of their price control agreement/settlement. It is a use-it-or-lose-it allowance, meaning that the amount that a DSO receives depends on how effectively it shows, in its innovation strategy, that it has planned its innovation efforts to be realised over the price control period. The value of the Network Innovation Allowance will be between 0.5% and 1% of base revenues.

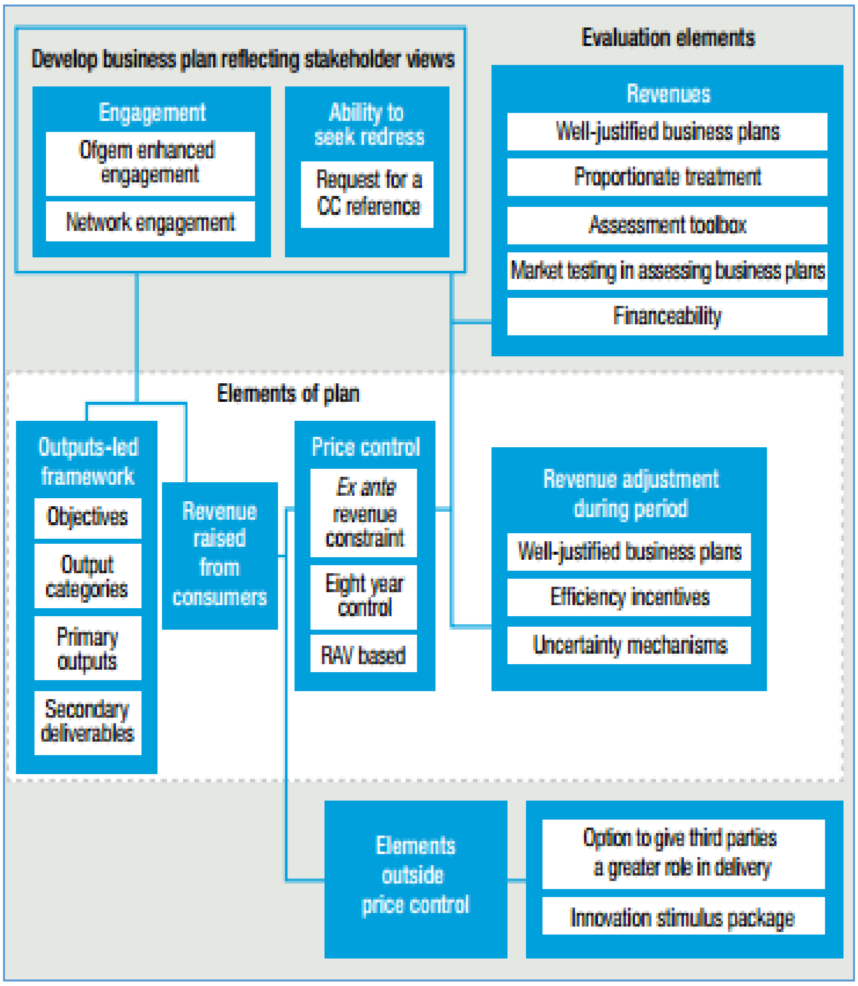
   The default level of funding will be 0.5% unless the DSO produces a clear, coherent and well-justified innovation strategy that exceeds the minimum requirements and fully-justifies why additional funding of up to 1% is needed.
2. **Network innovation competition** – this is a single and annual competition which funds large-scale and innovative projects with environmental and low-carbon benefits. DSOs can receive up to 90% of project funding through the competition.
3. **Innovation roll-out mechanism** – a revenue adjustment mechanism which is designed to provide funding for the roll-out of proven low-carbon and environmental innovations during the price control period. The criteria for eligibility for funding are set in a specific innovation roll-out mechanism license condition; there are two license application periods.

In order to set the allowed base revenues and the incentives which will apply during the regulatory period, DSOs and Ofgem must reach agreement, which is typically realised

[127] Ofgem, 2014. Regulatory regimes in GB – a high level summary. Received from: https://www.ofgem.gov.uk/ofgem-publications/90534/regulatoryregimesingb.pdf

following negotiations. The main elements of the RIIO process are shown in Figure 93. The process is initiated with stakeholder consultations and the DSO undertaken internal analysis on its future activities, which leads on to the development of the business plan. Specifically, DSOs need to submit well-justified business plans (covering the 8-year period), describing how they will meet the RIIO objectives. Plans are assessed against certain criteria, including efficiency considerations, and evidence of DSOs´ having engaged with stakeholders should be presented. Ofgem then makes a benchmarking analysis of the plans.[127]

Figure 93 - Main elements of the RIIO process



Source: Public Utilities Fortnightly, 2013[128]

In addition to projections of base revenues, DSOs´ business plans should either (1) acknowledge that Ofgem´s proposed mechanisms to manage uncertainty over the 8-year period are appropriate, or (2) provide evidence justifying why further revenue adjustment mechanisms will be needed. If DSOs also request changes from output incentives put forward by Ofgem, their plans must provide solid justification for why such changes are requested.[128] The main outputs include high levels of network reliability, availability, environmental impacts (decarbonisation and renewable targets), safety and customer satisfaction.

If a DSO´s business plan is considered to be of particularly high quality, it may be accepted by Ofgem as submitted and the company´s price control settlement will be fast-tracked. In other words, Ofgem can elect, at its discretion, to fast track a business plan if it determines that it meets high standards. DSOs which submit business plans which are not fast-tracked are requested to resubmit (improved) business plans.

In determining whether a business plan is eligible to be fast tracked, Ofgem makes a series of analyses of certain criteria. These are listed in Box 2. In order to qualify for being fast-tracked a business plan must demonstrate that it satisfactorily meets all of the criteria. The onus is on DSOs to demonstrate the cost-efficiency and long-term value for money of their business plans. Ofgem uses benchmarking of historical and forecast data in order to inform its assessments of DSOs´ forecasts, rather than as a means of setting specific allowances.

In making its costs assessments within the review of DSOs´ business plans, Ofgem uses a toolkit approach, comprising both Totex analysis and the use of disaggregated approaches. Totex analysis is claimed to assist in establishing the overall levels of efficiency of network operators; disaggregated assessments comprise separate reviews of operating and capital expenditures.

Box 2 – Five core criteria against which business plans are assessed

All DSOs´ business plans are assessed against the following questions under five core criteria. In order to be fast-tracked a DSO must demonstrate that its plan meets the criteria in all of the sections.

Process – has the DSO followed a robust process?

- Is the business plan clearly presented, with all key content included?
- Has the DSO engaged with stakeholder, and explained how this has influenced its business plan?
- Has the DSO submitted, and justified, all data tables and the PCFM?
- Does the business plan provide a strategy for long-term delivery?

Outputs – does the plan deliver the required outputs?

- Has the business plan covered the outputs specified in our strategy decision or provided clear and compelling justifications for any departures from the strategy decision?
- Has the DSO explained the resource implications for delivery of each output identified?
- Has the DSO explained how it will deliver outputs, and justified output baseline/forecast?
- Has the DSO explained the quality of its existing outputs and secondary deliverable (including information on asset health, criticality and asset risk) and how it plans to improve this information in the future?

Resources (efficient expenditure): Are the costs of delivering the outputs efficient?

- Has the DSO demonstrated that cost projections are efficient?
- How does the plan compare with others/does it reflect wider best practice?
- Has the DSO demonstrated that their financial costs are efficient (e.g. through market testing)?

[128] Public Utilities Fortnightly, 2013. A trip to RIIO in your future? Received from: http://www.brattle.com/system/publications/pdfs/000/004/958/original/A_Trip_to_RIIO_in_Your_Future.pdf?1386706496

• Has the DSO explained cost projections in the context of historical performance? • Has the DSO demonstrated a consideration of alternative approaches to achieving value for money in the delivery of its outputs? • Has the DSO clearly-linked its expenditure to relevant outputs and secondary deliverables? **Resources (efficient financing): Are the proposed financing arrangements efficient?** • Does the business plan conform to the financial policies specified in the strategy, are any departures well-justified? • Has the DSO provided evidence that financial costs are efficient? • Is the data in the plan consistent and has the DSO explained cost projections in the context of historical performance? **Uncertainty and risk: How well does the plan deal with uncertainty and risk?** • Has the DSO clearly articulated the key uncertainties it faces and considered how it will address them (e.g. including uncertainty mechanisms)? • Has the DSO considered risk and how to mitigate those risks?

Source: Ofgem, 2013[129]

During the process of developing their business plans, DSOs know the targets that Ofgem has set. DSOs can choose to accept Ofgem´s stated targets and incorporate them into their business plans; or alternatively, DSOs can propose the use of different targets, providing justification for why targets should differ from those set by Ofgem. In the second instance, a negotiation between the DSO and Ofgem is undertaken and a decision is reached regarding whether the DSO-proposed targets can be used.

DSOs which are put on the slow track are subjected to Ofgem´s analysis of appropriate expenditures for their activities in the following price control, even in the event that the price analysis differs significantly from the DSO´s submitted plan. The DSO can then accept Ofgem´s analysis of expenditures and agree to its use in the following price control. Or alternatively, the DSO can refer the final license amendments (suggested by Ofgem) to the GB Competition Commission for appeal. Third parties must cover the appeal costs themselves, and must prove to Ofgem´s satisfaction that they have sufficiently engaged with stakeholders within the price control review process. The appeal process should be resolved within 30 weeks.

4.4.2. Performance Rewards and Penalties under RIIO

RIIO provides DSOs with incentives which offer opportunities to benefit by receiving financial rewards for good performances, as well as incentives to avoid profit-reducing penalties. In fact, RIIO imposes numerous incentives on DSOs, covering a variety of performance criteria. In this section we explore those financial incentives.

One initial and straightforward incentive is the **Information Quality Incentive,** which relates to DSOs´ success in having their submitted business plan being fast-tracked. DSOs which are fast-tracked are allowed to receive upfront additional revenues equivalent to 2.5% of their Totex.

[129] Ofgem, 2013. Strategy decisión for the RIIO-ED1 electricity distribution price control. Received from: https://www.ofgem.gov.uk/ofgem-publications/47067/riioed1decoverview.pdf

The **efficiency incentive** on network investments is a measure which provides that DSOs which have their business plans fast-tracked also receive further advantage over those that do not have their plans fast-tracked, in that:

- Fast-tracked DSOs are allowed to retain 70% of their efficiency savings achieved within network investments; whilst
- DSOs which are not fast-tracked are allowed to only retain 45% - 65% of their efficiency savings achieved within network investments.[130]

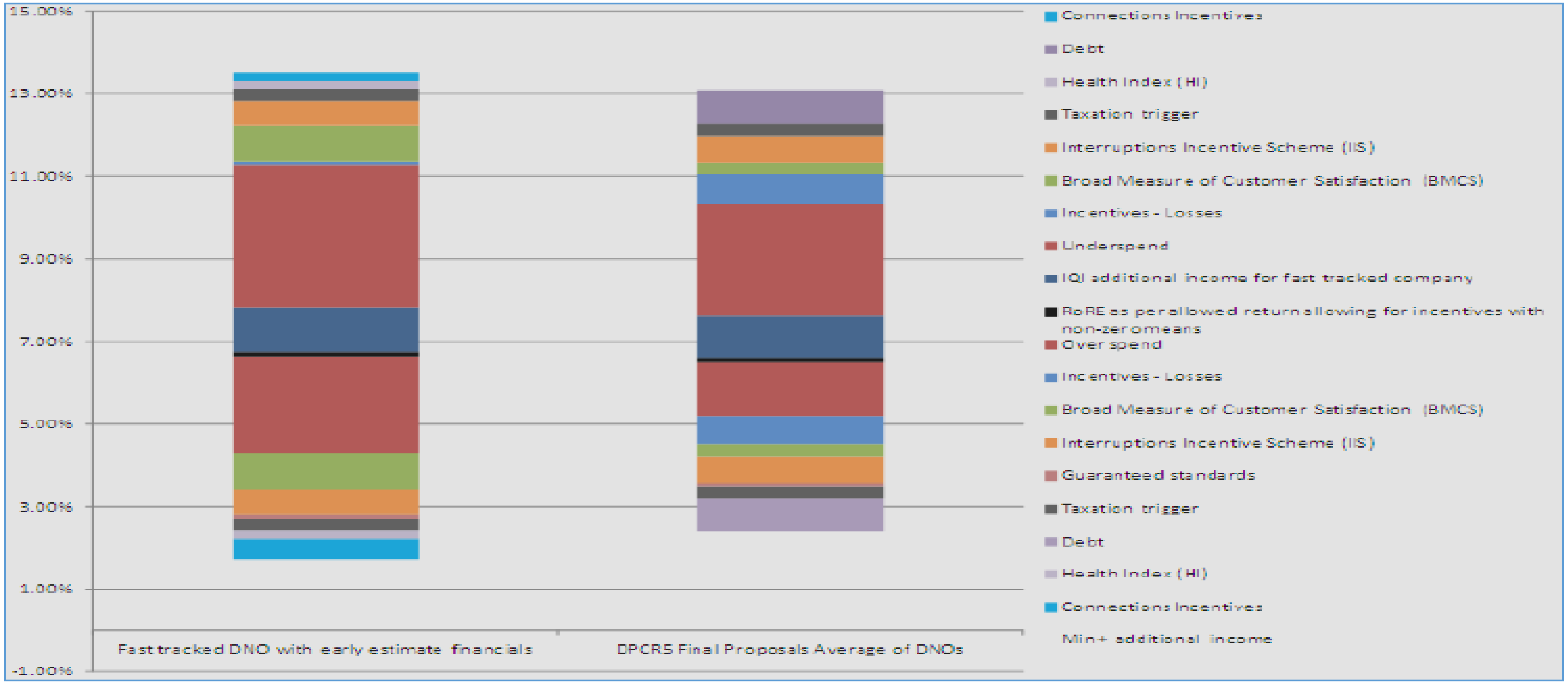
A further series of performance incentives acting on DSOs under RIIO are the potential rewards or penalties through the adjustment of the Return on Regulatory Equity (RoRE) under the Interruptions Incentive Scheme, which relates to **network reliability**. This incentive is discussed in Table 475 below. Such adjustments affect the returns to shareholders on the notional proportion of the Regulatory Asset Base that is financed by equity finance. The Interruptions Incentive Scheme in RIIO is retained from the previous regulatory scheme, the GB Distribution Price Control Review 5 (DPCR5).

Ofgem published analysis of a plausible RoRE penalty and reward range for fast-tracked electricity DSOs under RIIO-ED1 (due to begin in April 2015). This is shown in Figure 94. This is indicative of a possible range and should not be considered as binding. As mentioned above, the final scale of these incentives will become clear when Ofgem closes its price control, and following negotiations with individual DSOs.

For the purposes of comparison, the plausible RoRE penalty and reward range of Figure 94 is shown alongside that for the range used under the DPCR5, which was in effect from 1 April 2010 to 31 March 2015. It can be noted that the likely returns for electricity DSOs under RIIO are larger, in terms of both values and number of incentives, compared to the previous (non-RIIO) control period. Of particular note are the (larger) maximum efficiency incentive rate and the incentives for connections.

[130] DNV GL, 2014. UK´s RIIO and playing by the rules. Received from: http://blogs.dnvgl.com/utilityofthefuture/uks-riio-and-playing-by-the-rules

Figure 94 – Network reliability. Plausible RoRE range for a fast-tracked DSO in RIIO-ED1 (compared with DPCR5)



Source: Ofgem, 2013[131]

[131] Ofgem, 2013. Strategy decisión for the RIIO-ED1 electricity distribution Price control. Financial issues. Received from: file:///C:/Users/A406918/Desktop/riioed1decfinancialissues.pdf

Table 475 – Overview of main incentives for electricity DSOs

´Output´/ performance to be incentivised	How it is measured	Trigger	Scope of the incentive	Expected impact on RORE (or total allowed revenues)
Submission of high quality business plans for regulatory period	The quality of a DSO´s business plan is assessed based on five criteria, as described in Box 2 (above)	If a DSO´s business plan is fast-tracked, the company is provided with upfront additional revenue of 2.5% of totex. If the DSO´s business plan is not fast-tracked it does not receive this reward.	2.5% of a DSO´s totex	Between 0, and additional allowed revenues of 2.5% totex.
Efficiency improvements across operations	Positive cost savings, measured as the difference between realised and planned costs	The DSO can retain any cost savings it makes (the difference between realised and anticipated costs). DSOs can retain efficiency savings as follows: • DSOs with a fast-tracked business plan: 70% of efficiency savings; • DSOs without fast-tracked business plans: 45%-60% of efficiency savings.	Difference between realised (actually incurred) and planned costs	
Increased innovation	The degree to which Ofgem considers that a DSO has shown, in its innovation strategy, that it has planned sufficient innovation efforts (which will be realised over the price control period).	If the DSO´s innovation strategy is considered to be acceptable, 0.5% of its base revenues are allowed to be used to fund small-scale innovative projects. If the DSO produces a clear, coherent and well-justified innovation strategy that exceeds the minimum requirements and fully-justifies why additional funding is needed, a bonus, equivalent to (a further) 0.5% of base revenues can be allowed.		Between +0.5% and +1% of base revenues
Improved DSO performance in relation to dealing with customer complaints	The number and type of complaints received, and the time taken to resolve them	Targets are set for dealing with complaints (targets are set based on DSOs´ performance related to dealing with customer complaints in the pre-RIIO regulatory framework. Specific information on target levels has not been published). DSOs which fail to achieve target levels face a penalty of up to 0.5% of base revenues. DSOs which meet targets do not face any penalty (nor do they receive		Between 0 and -0.5% of base revenues

´Output´/ performance to be incentivised	How it is measured	Trigger	Scope of the incentive	Expected impact on RORE (or total allowed revenues)
		any reward). Targets are set which measure performance in 4 categories, each with a specific weighting: • % of total complaints outstanding after 1 day (10% weighting) • % of total complaints outstanding after 31 days (30% weighting) • % of total complaints that are repeat complaints (50% weighting) • Number of Energy Ombudsman decisions that go against the DSO as a % of the total complaints (10% weighting)		
Improved DSO performance in terms of delivering customer satisfaction	The Customer satisfaction survey measures overall customer satisfaction within three customer categories: (1) connections; (2) interruptions; and (3) general enquiries.	According to Ofgem, ´DNO performance in the customer satisfaction survey will be measured against fixed targets. Ofgem will gather data on performance in DPCR5 (the pre-RIIO regulatory regime) and use this to set targets for RIIO.´ The measure includes a factor of number of ´unsuccessful calls´ from customers experiencing an interruption (e.g. calls terminated by the DSO or calls abandoned by the customer in the queue). Overall performance score deteriorates the more calls it fails to answer.		± 1% of base revenues. Comprised of: Connections: ±0.5%; Interruptions: ±0.3%; and General enquiries: ±0.2%
Improved DSO engagement with stakeholders	The extent to which DSOs engage effectively with a broad range of stakeholders and use the outputs from the process to inform how they plan and run their business.	An overall assessment of DSOs´ performance in terms of engaging with stakeholder is made, with particular focus on DSOs´ efforts to address customer vulnerability. The DSO is eligible to receive up to 0.5% of base revenues reward in-line with Ofgem´s analysis of its stakeholder		Between 0 and +0.5% of base revenues

´Output´/ performance to be incentivised	How it is measured	Trigger	Scope of the incentive	Expected impact on RORE (or total allowed revenues)
		engagement performance.		
Reduced levels of electricity losses on the distribution network	DSOs´ performance is measured based on: • Companies understanding of their losses and preparation for a measurable losses incentive in the second RIIO period • Effectiveness of actions taken to reduce losses, including any actions which have achieved losses reductions which are substantially greater than forecast • The demonstrable engagement of DSOs with their stakeholders (e.g. connection customers, supply chain partners) on losses • Innovative approaches to losses reduction (outside of any projects funded through the innovation stimulus mechanisms) • Performance against the strategy set out to address losses • Sharing of best practice with other companies	DSOs may receive payments from a limited fund amount. Specifically, DSOs may receive rewards for good performance, from money within the Losses Discretionary Award of up to GBP 32 million across all electricity DSOs, awarded in three tranches over the 8 year regulatory period, as follows: one tranche of up to GBP 8 million in year 2; a second tranche of up to GBP 10 million in year 4; and a final tranche of GBP 14 million in year 6. DNOs wishing to participate in the DR will be required to submit evidence against the scorecard criteria. The criteria could be weighted differently over the three tranches. Ofgem will assess the submissions, with expert advice where necessary, and make recommendations to the Authority	Fixed amount fund of GBP 32 million to be dispersed over the 8-year regulatory period	Rewards only, with amounts not linked directly to RORE
Reduced levels (number, frequency, duration) of interruptions	Measurements of the number and duration of network supply interruptions versus a target derived from benchmark industry performance	DSOs are measured in relation to their performance against interruptions targets, where separate targets are used respectively for planned and unplanned interruptions. Annual DSO targets for planned interruptions will be set at the annual average level of planned interruptions and minutes lost over the previous 3-year period. There is a 2-		Reward or penalty of up to 250 RORE basis points per year

´Output´/ performance to be incentivised	How it is measured	Trigger	Scope of the incentive	Expected impact on RORE (or total allowed revenues)
		year lag on the years utilised in setting the targets. DSOs are rewarded or penalised based on the difference between their actual performance and the target (and using an incentive rate that is 50% that of unplanned interruptions). With regard to unplanned interruptions targets, specific targets are set for each DSO upfront (based on pre-RIIO framework performances). Each DSO can receive a reward or penalty of up to 250 RORE basis points per annum, depending on how their actual performance compares to set targets.		

Source: Ofgem, 2013[131]

Country Report – Great Britain (gas distribution)

1. Overview of to the distribution sector

There are 4 large-scale DSOs active in the gas distribution sector in Great Britain, which are legally-unbundled. The 12 DSOs which supply a customer base of less than 100.000 supply around 0,4% of total gas demand.

The regulator determines the amount of allowed revenues; in 2013 these were € 3.291 million.

1.1. Institutional structure and responsibilities

In Great Britain there are 31 distributors supplying gas to 23.329.812 customers covering an area of 230.000 km^2. Gas distribution networks do not cover the full footprint of Great Britain; however, DSOs are licensed to provide an emergency service to respond to any reported gas escape. Summary data on industry structure is set out below.

Table 476: DSO characteristics

	Total number DSOs	Ownership unbundled	Legally unbundled	Less than 100,000 customers	Exemption*	Share of total demand
Country	31	-	8	12	No	0,4%

***exemption from distribution network charges for certain types of grid users, such as low-carbon generation connected to distribution networks.**

The responsibility for defining the allowed revenues of DSOs is set solely by the NRA, Ofgem. With regard to defining the tariff structure, the DSO proposes the tariff structure and the NRA takes a final decision on whether it is acceptable or not, following consultations with relevant stakeholders.

The breakdown of responsibilities as it related to tariff setting is summarized in the table below.

Table 477: Legal basis for tariff structure – Roles and Responsibilities in setting distribution tariffs

Actor	Allowed revenues (tariff level)	Tariffs (tariff structure)	Connection charges
DSO	Not involved	Proposes the tariff structure	Proposes methodology to calculate the charges.
Government	Not involved	Not involved	
NRA	Full responsibility for setting allowed revenues	Consults with stakeholders on the DSO´s proposed structure. Takes final decision	Consults with stakeholders, assesses the methodology. Takes a final decision on the methodology principles (not responsible for approving the actual connection charges)

X = main responsibility; other options to fill the table: sets rules; monitors ex-post; defines main principles; calculates for NRA approval; also involved;

The regulatory process adopted to setting distribution tariffs is that DSOs set charges using a methodology approved by the regulator (i.e. the regulator does not technically approve the charges).

1.2. Key figures on revenue and tariffs

Distribution revenues in Great Britain in 2013 were € 3.291 million, broken down by the following activities:

- Distribution – € 3.237,8 million (98,4%)
- Metering – € 53,8 million (1,6%)

There are no typically customer category definitions. However, the NRA generally considers a typical household to have a consumption of 15.000 kWh.

2. Regulation of distribution activities

The regulatory model includes incentives on efficiency and quality output incentives.

The tariff regime has duration of 8 years, to provide longer-term regulatory stability.

2.1. General overview

The regulatory model includes incentives on efficiency (the totex incentive regime) and incentives to perform well and/or outperform various quality output measures.

The up-front revenue control of 8 years is set using the RIIO approach (Revenues = incentives + innovation + outputs) price control. This is an 'incentives-based' approach involving:

- Setting Totex allowances
- Totex Incentive Mechanisms
- Additional range of incentive adjustments included in allowed revenue formula

Key features of the regulatory regime are set out in the following table

Table 478: Main features of the regulatory regime

Issue	Approach
Type of regime (concession/licence)	License
Duration of tariff setting regime	8 years
Form of determination (distributor propose/regulator decide)	The regulator is the only organisation involved in setting and deciding on the allowed revenues
Scope for appeal regulatory decision	DSOs may appeal to the Competition and Markets

Issue	Approach
	Authority, with respect to any license modifications, when the NRA goes against Panel Recommendations. DSOs may appeal to the Competition Appeal Tribunal (in respect of the Competition Act 1998 on competition law infringements, such as an abuse of dominance, the existence of cartels, etc.) A Statutory Appeal can be made to the High Court, in respect of the NRA´s enforcement decisions which imposed a penalty for the breach of license conditions or a relevant requirement. An appeal may also be made to the High Court for judicial review, with respect to any decision which cannot otherwise be appealed.

2.2. Main incentive properties of the distribution regulatory model

The following key regulatory incentives apply for the DSOs:

- Efficiency incentives
- Incentives to perform well and/or outperform various quality output measures.

At the same time the following tools are provided to mitigate risks:

- Profit sharing
  - Totex Incentive Mechanisms which includes a sharing mechanism for over-spend and under-spend by a company. Under the sharing mechanism, the DNO retains a fixed percentage (around 60%) of any profit and the customers receive around 40%). The same applies to any over-spend.
  - Financeability analysis at the price control setting stage
  - Uncertainty Mechanisms (The Annual Iteration Process for the RIIO-GD1 Price Control Financial Model allows factors to be taken into account on a real-time basis)
- Volume risk
  - Gas DSOs are required to come within 88% and 112% of revenue by managing charges. Over- and under-recovery is then reflected in the ´correction factor´ term in the allowed revenue formula.

2.3. Determination of cost of service parameters

The approach to determining key cost of service parameters are summarized in the following table.

Table 479: Approach to key cost of service parameters

Parameter	Approach
Form of price control	Revenue based with efficiency adjustments
Regulatory asset base	
Capital expenditure	Total expenditure benchmarking
Approach to operating expenditure	Total expenditure benchmarking
Form of WACC applied	Real Vanilla WACC

The Vanilla Weighted Average Cost of Capital is the NRA´s preferred way of expressing the rate of return allowed on the Regulatory Asset Values (RAV) of price controlled network companies. Using Vanilla WACC means that the company's tax cost is separately calculated as a discrete allowance so that you only have to factor in:

- The pre-tax cost of debt - i.e. the percentage charge levied by lenders, and
- The post tax cost of equity – i.e. the percentage return equity investors expect to actually receive, weighted according to the gearing assumption being used.

The NRA uses the "Real Vanilla WACC" which gives a lower percentage than "Nominal Vanilla WACC" would (when inflation is positive). This is because they RPI index RAV balance values upon which the Vanilla WACC return is given. The WACC formula uses notional gearing, which is broadly reflective of business gearing levels.

3. Tariffs for distribution services

Customer and system charges are used in cost recovery via distribution tariffs.

Tariffs are not geographically-uniform, are non-linear, and are not regulated.

Connection charges are deep, and the connecting customer pays for the full costs of connection including any reinforcement that may be needed to the network in that area.

3.1. Distribution tariffs

In the process of recovering costs, two types of charges – system and customer charges – are generally applied, and which have the following traits:

- System charges: Costs include all work relating to assets upstream of the service pipe and for managing the flow of gas through the system. These are attributed across the four main tiers and eight sub-tiers in the network.
- Customer Charges: Costs comprise those associated with service pipes and those associated with emergency work. These are divided across the consumption bands based on weighted consumer numbers by consumption band. Total average costs per supply point are calculated for each consumption band.

Various other aspects of distribution tariff setting are summarized in the table below.

Table 480: Approach to key issues in setting distribution tariffs

Issue	Approach
Treatment of distribution losses	Included in DSO tariffs. Note that this is subject to a volume cap to limit the exposure of consumers to loss levels

Issue	Approach
Presence of uniform tariffs	No
Presence of non-linear tariffs	Yes
Presence of regulated retail tariffs	No
Presence of social tariffs	No

As part of the allowed revenues gas DSOs are given an allowance with which to replace the volume of gas lost to shrinkage on its network. This allowance flows through into the tariffs paid for by customers.

There are eight distribution networks owned by four different distribution licensees. Each one charges different tariffs, depending on allowed revenue, cost of the specific network, etc. It can be noted, however, that the methodology used to calculate the charges is the same for each company.

3.2. Connection charges

Key issues in the setting of connection charges are set out in the table below.

Table 481: Summary of key issues relating to connection charges

	Issue	Approach
Determination of charges	Type of charges (shallow/deep)	Deep
	Methodology adopted	Each Company runs their own connection charging methodology which the NRA approves. Charges are calculated to reflect the cost of labour, materials, and any other expenses required to carry out the work.
Hosting capacity	Scope to refuse connection	No, a connection offer and quote must be provided
	Requirements to publish hosting capacity	None
	Targets and/or incentive schemes to enhance hosting capacity	Not applicable

The connecting customer pays for the full costs of connection including any reinforcement that may be needed to the network in that area.

Any upstream (wider) reinforcement required is not covered by the connecting customer. Upstream reinforcement is only likely for quite large new connections in these cases a customer has to provide an Advanced Reservation Capacity Agreement (ARCA) which commits the new supply point (or increase to existing supply point) to use the additional capacity it requested. If following connection it doesn’t use the capacity the customer may have to pay for the costs of the unused additional upstream reinforcement.

DSOs must provide connection offers. That connection offer may have quite high costs and therefore be unfeasible to the customer, but the DSO must least provide a quote.

GDNs are required to submit capacity information to us as part of their annual report (RRP) which essentially relates to the capacity and utilisation of network off-take stations and pressure reduction stations (PRSs).

4. Distribution system development and operation

DSOs publish a planning document on an annual basis, and which has a 10-year Outlook.

DSOs are responsible for providing metering services, and these can be out-sourced if the DSO chooses to do so.

As of 2013 there were 160.187 (domestic) smart meters installed in Great Britain (in the residential sector).

4.1. Distribution system development

The key features of distribution system planning are summarized below.

Table 482: Approach to distribution planning

Issue	Approach
Form of distribution planning document	There is a requirement to publish an annual Ten Year Statement which sets out the DSOs´ assessment of their future supply & demand position
- Key responsibilities for its development	The plan is prepared by the DSO
- Degree of integration with renewables plan	Indirect integration. Under the RIIO-GD1 price control GDNs are incentivised to reduce leakage and energy consumption, to innovate through allowances and competitions, and to encourage / facilitate biomethane injection connections.
- Relationship with consumption trends	The Ten Year Statement specifically describes the DSOs´ assessment of future consumption
- Relationship with quality of service targets	A balance is struck between business plans and quality of service targets
- How trade-offs between network development and alternative technologies are treated	No specific trade-offs
- Requirements to integrate cost benefit analysis	The business plans for the price control are scrutinised and cost benefit analysis is used to ensure DSOs´ investment is appropriate and gives gas consumers good value for money. This happens every 8 years.

In the price control, a balance is struck between the impacts of the GDNs business plans and the quality of service targets that are consistent with the allowed network investments.

4.2. Metering

Key issues regarding metering, and the role of the DSOs, are set out in the following table.

Table 483: Key approach to metering

Issue	Approach adopted
Discos role in metering	Responsible for metering service provision, including providing meters to consumers
Monopoly services in the metering	No the metering market is liberalised
Smart metering functionality	Half-hourly measurements Remote reading Remote disconnection and reconnection of customers Smart meters are capable of receiving tariff information and passing it on to appliances which can be programmed to react in a particular way (i.e. to turn on once tariff is low enough/ turn off if it rises to a given price). The smart meter therefore facilitates remote operation of appliances at the customer's premises. Local ports send real time consumption information to local screens or computers

DSOs are allowed to source metering services from alternative suppliers or National Grid (Gas DSO).

For meters owned by the gas DSO, the metering services are unbundled. This means, the metering costs are separated out and subject to price control.

Gas DSOs still maintain an obligation to provide gas meters when requested to do so by a gas supplier. Services are charged at a tariff not exceeding a regulated rate (i.e. as part of the Price Control). The gas DSO obligation to provide meter services will end with the transition to smart meters.

As of 2013 there were 122.707 (domestic) smart meters installed in Great Britain, and some 10.535 smart meters installed in non-domestic properties. A breakdown by customer category is illustrated below.

Table 484: Number of smart meters installed – by end of 2013

Customer category	Number
Residential	122.707
Non-residential / Industrial	10.535
Total	122.707

The Smart Meters deployment plan is coordinated and approved by the GB Government (Department of Energy and Climate Change). The current deployment (unit installation) plan as of February 2014 is as follows:

Domestic smart meters:

- 2014 – 311,752
- 2015 – 3,004,859
- 2016 - 2,688,893
- 2017 – 4,112,739
- 2018 – 4,799,115
- 2019 – 4,602,174
- 2020 – 3,724,653

Non-domestic meters:

- 2014 – 31,430
- 2015 – 27,729
- 2016 – 60,315
- 2017 – 78,070
- 2018 – 85,521
- 2019 – 86,643
- 2020 – 75,401

The share of consumption by non-daily (or hourly) metered end-customers is around 79%. Non-daily metered consumption is estimated through Data which is gathered from customers who are asked to provide current meter readings. The regularity of these reading requests varies. Additionally, suppliers do their own meter readings according to their own policy, but this must be at least every 2 years. The suppliers apply a proportionality test when deciding on the frequency of meter readings.

The following preliminary information on the impact of smart meter roll out is available.

Table 485: Effects from the smart meters deployment.

DSO	Total number of households	Number of households with a SM	Gas consumption reduction	Euro saved per year for an average household
North West	2.678.671	Data unavailable	Approximately 2%	Data unavailable
West Midlands	1.954.342	Data unavailable	Approximately 2%	Data unavailable
EoE	4.192.590	Data unavailable	Approximately 2%	Data unavailable
London	2.072.093	Data unavailable	Approximately 2%	Data unavailable
NGN	2.684.371	Data unavailable	Approximately 2%	Data unavailable
Scotland	1.790.322	Data unavailable	Approximately 2%	Data unavailable
Southern	4.063.607	Data unavailable	Approximately 2%	Data unavailable
WWU	2.485.923	Data unavailable	Approximately 2%	Data unavailable

Specific data on the impacts of the gas smart meter rollout is not publicly-available. The GB Government estimates that its gas smart meter rollout policy in GB (through a supplier-led rollout and with a centralised data and communications company) will deliver energy savings in the residential sector which are equivalent to:

- Low case – 1% gas saving;
- Central case – 2% gas saving; and
- High case – 3% gas saving.[132]

Anticipated savings in the non-domestic sector are generally higher, as follows:

- Low case – 3,5% gas saving;
- Central case – 4,5% gas saving; and
- High case – 5,5% gas saving.[133]

[132] GB Government, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/276656/smart_meter_roll_out_for_the_domestic_and_small_and_medium_and_non_domestic_sectors.pdf
[133] GB Government, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/276656/smart_meter_roll_out_for_the_domestic_and_small_and_medium_and_non_domestic_sectors.pdf