



## **POLICY GUIDELINES**

*by the Energy Community Secretariat*

**on the distribution network tariffs**

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## 1 CONTEXT

Distribution network tariff setting is a key competence of national regulatory authorities (hereinafter 'regulatory authorities' or NRAs) according to the Energy Community *acquis communautaire* (hereinafter 'acquis').

The legal framework requires regulatory authorities to ensure that network tariffs are transparent, cost-reflective and allow for the necessary investment in networks. The Third Energy Package, incorporated in the acquis by Decision 2011/02/MC-EnC of the Energy Community Ministerial Council, additionally requires regulated tariffs or the methodologies for their calculation to ensure that system operators are granted appropriate short- and long-term incentives to increase efficiency, foster market integration as well as security of supply and support related research activities.

The methods of economic regulation of natural monopolies, applied in the Energy Community include rate of return, price cap, revenue cap, yardstick regulation including benchmarking elements, performance standards or a combination of these methods. Today, there is a general trend to shift from a return-on-capital-regulation to more sophisticated incentive-based regulation.

The present Policy Guidelines aim to provide guidance to regulatory authorities, but also the regulated industry, as regards to substantiated best practises in applying the principles of objectivity, non-discrimination, transparency, stability, predictability, cost effectiveness, cost recovery as well as cost reflectivity in distribution tariff setting. In this attempt, the Energy Community Secretariat seeks to contribute to the discussions on appropriate distribution tariffs currently ongoing in the Contracting Parties, while at the same time fully acknowledging the independence of regulatory authorities in designing national grid fees.

The recommendations of the present Policy Guideline are applicable to both the electricity and gas sector, unless otherwise indicated.

## 2 PRINCIPLES

A number of core principles of tariff regulation and regulatory best practise are commonly acknowledged.

A proper regulation method lowers the risk for investors and directly impacts and lowers the cost of capital. The method of regulation depends on the structure of the sector and its level of development and evolves with the development of regulatory tools as further described hereinafter.

### *PREDICTABILITY*

- Whichever regulation method is applied, it is expected to define as clearly as possible the principles, procedures, criteria and parameters for tariff setting, to constrain the regulator's discretion and to provide investors with a long term warranty that invested capital will be paid back including a reasonable rate of return.
- The tariff methodology has to be consistently applied and be as stable as possible. Any subsequent change to the effective tariff methodology has to take fair account of its impact on the existing contractual commitments undertaken by the network operator.

- Investment decisions of network operators have to be evaluated taking into account the information and evidence known or that should have been known to a reasonably informed operator at the time when the decision was made.

#### *TRANSPARENCY*

- The procedure and methodology for setting tariffs have to be made public sufficiently in advance of their entry into force and effective implementation.
- Public consultations best serve the purpose of collecting views from the broader public. Any tariff request of an applicant and tariff proceedings must be public. The procedure and rules for involvement of other interested stakeholders, including customer organizations and the general public, should be defined in advance.
- When the regulatory authority's task is to approve the tariffs proposed by a network operator, the methodology has to be clear, understandable and comprehensive enough to allow the regulated undertaking to fully perceive its future position.
- When the regulatory authority has the competence to set the tariffs, all relevant data, facts and evidence used for assessment and recognition must be clearly defined. Data and all other elements relevant for tariff application must be available or accessible to the distribution system operator (DSO).

#### *RESPECTING THE ECONOMIC ENVIRONMENT*

- The regulation method should generally reflect the specificities of each country with regard to the network structure, number and size of DSOs, the maturity of the regulatory framework and other country characteristics.
- Thus, each regulatory authority should prudently define the tariff methodology tailor-made for its energy sector and licensed DSOs, taking into account specific existing circumstances and the expected, planned and desired development of the energy sector and the overall economy.
- If the general economic interest requires so, the network tariffs may be set uniformly across the jurisdiction. Otherwise, tariffs are set for each DSO and applied in their respective area. If uniform tariffs are applied, the procedure for reconciliation and settlement among DSOs must be defined in advance and implemented.

#### *REGULATION METHOD*

- An optimal price regulation model is a coherent mix of the most appropriate regulation tools under the existing circumstances with the view to achieve the desired development.
- For initial regulatory assessments, the Cost Plus Method is most appropriate, with capital costs regulated by using the Rate of Return regulation.
- Yardstick or Benchmarking Methods are difficult to apply where only one or two operators are regulated. If benchmarking is used, the analysis should properly reflect the overall economic, legal and regulatory environment.
- In the absence of reliable and comparable data for benchmarking, the Revenue-Cap or Price-cap Regulation Method with efficiency incentives are more appropriate.
- The Yardstick Regulation Method is the most common method to set a utility's efficiency targets.

- Incentive regulation is the best tool to achieve cost efficiency and to maintain the required level of quality, under the condition that the required or guaranteed level of quality of service has been established and maintained.
- If incentive regulation is applied, the length of the regulatory period should be sufficient to allow the regulated utility not only to reach the efficiency targets but even more importantly to reap benefits from it until the next price setting period.
- The positive correlation between a longer regulatory period and regulatory stability has to be observed as the leading principle.
- The Performance-Based Regulation Method, setting a quality of service bonus / malus for deviation from a predefined quality target, is best fit for advanced regulatory systems with consistent and continuous monitoring and a solid database.

### 3. REQUIRED REVENUES FOR NETWORK OPERATION

The regulation methods in use generally reflect the specificities of each country with regard to the energy system structure, the number and size of DSOs, the maturity of the regulatory framework and other country-inherent characteristics.

Whatever method or combination of methods is applied, the first step in the tariff setting process is the determination of revenues required to cover all reasonable and prudently incurred costs, taking into account network development needs.

As there are different approaches to determine the required revenues, an initial assessment and recognition of historic costs is a precondition to building up to advanced regulation methods.

#### 3.1 FIXED ASSETS: CLASSIFICATION, DISCLOSURE AND RECOGNITION

There is no doubt that costs related to the acquisition, use and maintenance of fixed assets necessary for the operation of a distribution system are to be recovered from regulated network tariffs. Still, clarification is needed as to which assets exactly are necessary for the operation of the system and, thus, are to be recognized by regulatory authorities.

Regulatory authorities throughout the Energy Community refer to these assets as "Regulatory Assets" or the "Regulatory Assets Base" (RAB).

Regulatory authorities assess and recognize which assets are necessary for operation either ex-ante or ex-post.

Ex-ante recognition assumes that the regulatory authority will define and classify the assets necessary for operation of a distribution system in its tariff methodology or in a rule accompanying the tariff methodology. In case of ex-post recognition, the operator presents to the regulatory authority, after the investment decision or after acquisition, evidence of the fixed assets in operation and proves their use and usability.

In both cases, the core principles shall be respected by regulators to allow for predictability and transparency.

### 3.1.1 RECOGNITION OF FIXED ASSETS IN RAB

#### IDENTIFICATION OF ASSETS

- Principles and criteria for recognition of fixed assets have to be known in advance and applied consistently.
- If changes to the established principles and criteria have to be introduced, they also have to be announced sufficiently in advance and the overall impact of the changes has to be considered.
- For cost effectiveness of the tariff procedure and regulatory decision-making, it is recommended to keep a register, or a special identification of assets necessary for operation of the distribution system, separate from other assets held by the operator.
- Assets not intended for the distribution functions should be excluded from the RAB. If distribution assets are acquired at no cost by the operator, these assets should be excluded from the RAB or recognized through revenue adjustment.
- Assets that have reached the end of their economic lifetime and have zero carrying value but are still usable and used by the DSO, should not be written-off and excluded from the RAB automatically.
- Some form of incentive for the DSO not to scrap usable assets, even if their carrying value is zero and earn no profit, should be provided in order to maximize the overall welfare for both sides.

#### CONNECTION EQUIPMENT

- Capital contributions and assets financed by third parties are usually excluded from the RAB. If not explicitly excluded, the regulatory policy and methodology must be clear as regards the corresponding costs and revenues.
- If assets procured or financed via a grant or customers' contributions are included in the RAB, the customers' contribution has to be reflected through revenue adjustments. Whatever the approach, it has to be transparent and applied in a consistent and systematic manner.
- End-users' contributions should be incorporated in the regulatory framework through the revenue adjustments, rather than through asset exclusion from the RAB.
- A connection fee paid by end-users either through a cash contribution or through connection assets construction should be recognized and treated in the same manner.
- Depending on the regulatory framework, connection facilities procured or financed by network users may be included in the RAB.
- As a matter of consistency, if costs are not recognized within the approved operation and maintenance costs, any corresponding revenues earned from usage of such assets must not be calculated as a deductive item.

## OTHER FIXED ASSETS IN RAB

- Intangible assets such as software, copyrights and similar are recognized as a part of the RAB.
- Due consideration should be given to the specifics of goodwill including ex-ante definition of its treatment. In principle, if the tariff methodology is based on RAB identification, goodwill should not be included in the RAB.
- Working capital is usually an integral part of the RAB. The recognition of the required amount of working capital has to be flexible to reflect changes in the business environment and requirements imposed on DSOs.
- Recognition of construction work in progress, either at the amount of carrying value of the investment costs or the planned amount, shall reflect the prioritization of the regulatory objectives. If recognized and included in the RAB, it is reasonable to have the investment plans submitted to and reviewed by the regulatory authority.

### 3.1.2 VALUATION OF FIXED ASSETS

The system operator has to prove that fixed assets, used and usable for operation of the distribution system, are carried at fair value. The common and reasonable approach to determine the fair value of an item or group of items is to look for a corresponding market price.

The underlying principle to substantiate the claim that acquisition costs reflect the market price is that assets are procured in a transparent and non-discriminatory procedure. Distribution system operators, as entities having the exclusive right to operate in a given geographic area, are obliged to procure all assets in a transparent and non-discriminatory public procurement procedure.

The paramount principle for recognition of the fair value is prudence. Prudence requires the disclosure of assets at costs or at net realizable value, whichever is lower.

#### INITIAL RECOGNITION

- If the asset records are reliable and there is no indication of impairment, the Historic Cost Method is most appropriate to determine the fair value of assets. The tear and wear of an asset during a reporting period is disclosed and recognized as cost of depreciation. The carrying value of an asset is the difference between the costs of acquisition as recorded in the books of accounts and the corresponding accumulated depreciation.
- Recalling the paramount principles of predictability and consistency, annual adjustment of the RAB during a regulatory period should be avoided, unless the annual ratio of new investments' value and depreciation significantly deviates from the unity value.
- When necessary, differences may be reconciled during several years of the subsequent regulatory period in order to flatten sharp increments, positive or negative, to avoid sharp changes caused by reconciliation of differences from the previous period over the subsequent period.

## REVALUATION

- When evidence of the fair value of assets is missing as a result of poor records, currency exchange rate volatility and inflation, assets have to be revalued.
- In that case, the Replacement Cost Method is an optimal solution to determine the fair value of RAB. Such value should be checked against the market price, whenever possible, for individual assets or a group of assets.
- Revaluation based on discounted future cash flow from the regulated activity should be avoided due to its inherent circularity (future cash flow based on expected regulated revenue, whereas regulated revenues depend on the value of assets).
- Regulatory authorities need to have extensive competences with regard to the initiation and approval of the revaluation of fixed assets.
- Treatment of the revaluation reserve, revaluation surplus and impairment has to be defined in advance and consistently applied.

### 3.1.3. DEPRECIATION AND AMORTIZATION

Depreciation is an accounting tool for systematic allocation of the cost of an asset (for wear, tear and obsolescence) to the accounting periods in which the asset provides benefits to the company and also an instrument for recovery of invested capital in fixed assets.

The depreciation policy is one of the key preconditions for stability and predictability of the regulatory framework providing certainty to investors that the invested capital is recovered during the asset's life time.

In traditional regulatory frameworks, straight-line depreciation is the common approach that assumes a linear relationship between accumulated depreciation and the age of the asset relative to its expected economic life. This method represents the well proven approach in the electricity and gas distribution sector that provides stable cash flow for the DSO and gives more price predictability for end-consumers.

The use of the accelerated depreciation method with decreasing allocations might be justified where assets can be expected to be exploited in earlier years or when the regulator decides to adjust the depreciation period to ensure that the periods of cost recovery and debt repayment are aligned to a reasonable extent.

Functional depreciation is based on the number of units of outputs created from the usage of an asset.

### RECOGNITION OF DEPRECIATION AND AMORTIZATION

- Regulatory depreciation periods aligned to the extent possible with the already applicable accounting practice and/or the technical lifetime of network assets facilitate the regulatory procedure and lower administrative costs.
- If specific regulatory accounting rules are introduced, the advantage has to outweigh the costs of maintaining parallel reporting and accounting.

- The regulatory depreciation policy should be consistently applied throughout the lifetime of the network assets. In case of change, the impact has to be adequately addressed in particular in the light of the predictability of tariffs and stability of the regulatory framework. Specific lifetime and depreciation rates for individual asset types are preferred compared to lump values at the network level.
- The regulatory depreciation policy should strive to avoid either the risk of asset stranding due to too long assumed regulatory lifetimes or the risk of overinvestment due to too short lifetimes when fully functional assets are being replaced solely because they do not generate returns.
- If there is a difference between the regulatory depreciation method and the depreciation method reported for tax purposes, additional taxable differences may occur. These items should be addressed in the methodology, as appropriate.
- The functional depreciation method is convenient when the usage significantly varies over the useful life of an asset in order to avoid significant changes in average costs of service per unit of output.

### 3.2 RETURN ON ASSETS

A reasonable rate of return in combination with a consistently applied depreciation policy should provide strong regulatory commitment that the invested capital may be recovered and that the DSO has at its disposal sufficient funds to finance network investments.

The impact of the rate of return on RAB on the total retail prices level needs to be considered, as its level has much broader relevance. A reasonable rate of return is also seen as a key precondition for quality of supply regulation.

For calculation of the return on the RAB, a common approach in European countries is the Weighted Average of Capital Costs (WACC) method, calculated as weighted cost of debt and equity related to the DSO's capital structure.

An important parameter in WACC calculation is gearing (also called financial leverage) that reflects the percentage of capital available for an enterprise that is financed by debt and long-term arrangements.

As a result of a stable regulatory environment, distribution utilities are able to maintain (for a given rating category) significantly more debt relative to cash flow than competitive industries. However, if business risks were to increase for utilities in the future, it would be likely that utility debt leverage (e.g. debt relative to overall capital) would need to be reduced in order to retain credit ratings.

#### SETTING WACC RIGHT

- The rate of return set at a reasonable level reflecting the prevailing broader market conditions in the Energy Community and the respective Contracting Party, with gradual changes, if necessary, is assumed to bring more predictability and investor confidence.
- Without prejudice to the method and parameters used to calculate the rate of return on equity, the rate has to be sufficient to keep investors in business.

- A low rate of return directly impacts the DSOs' cash flow and is likely to cause financial risk and higher costs of debt with possible difficulties in accessing financial markets and adequate loans.
- Regulatory authorities may decide to use the actual gearing ratio or otherwise set an assumed optimal capital structure with the expectation that regulated utilities should stick to the regulated value. The selected option will depend on the overall regulatory policy, taking into account the maturity and developments in the financial market.
- The regulatory approach to gearing should be defined on a long-term basis and consistently applied.
- In situations when companies face bankability problems as a result of excessive indebtedness, regulatory authorities may require a company to maintain an investment credit rating provided by an independent rating agency.
- Having in mind the generally low risk of the regulated distribution activities, it is expected that the equity beta used in WACC calculation should be set lower than unity in any case.
- Keeping the rate of return low as a means to protect vulnerable consumers and, consequently, keeping a low level of retail prices, should be avoided as it is likely to endanger the medium and long-term sustainability of the energy sector due to distorted price signals.
- Furthermore, trade-offs between the approved amounts of return on assets and other costs should be avoided as they negatively affect the transparency of the tariff setting process.

### 3.3 OPERATING COSTS

Regardless of the regulation method applied, the regulator sets the allowed revenue based on the utilities' past performance. The cost situation in the base year is therefore crucial for determining the allowed revenue for the following regulatory period.

As a general rule, regulatory authorities recognize only the reasonable costs incurred in the efficient running of the network.

The regulator may conduct its own assessment of the reasonableness and prudence of incurred costs or base its judgment on benchmarking with comparable undertakings.

Different indicators of average operational expenditure (OPEX) may be applied for comparison purposes such as: OPEX compared to the number of connections; OPEX compared to the length (km) of (pipe)lines, etc. Different circumstances should be taken into account by regulatory authorities when allowing reasonable operation and maintenance (O&M) costs such as: network density, the share of underground electricity cables or, in gas distribution, the share of pipelines above ground, the network's age or geographic and climate conditions.

#### RECOGNITION OF JUSTIFIED COSTS

- The recognized OPEX is commonly based on *historic costs*, preferably normalized over a relatively longer period of at least three years.

- The regulator may apply a number of methods to assess what is the appropriate level of the controllable operation and maintenance costs, whereby *benchmarking* is the most commonly applied method to evaluate the DSO's efficiency and to recognize a reasonable level of costs.
- The regulatory framework is expected to provide clear definitions of *controllable and non-controllable* operating costs, particularly if incentive regulation is in force.
- Incentive regulation is the best approach to reach a level of operating costs appropriate for an efficiently run network undertaking.
- During the regulatory period, the controllable OPEX should be *adjusted* to the increments of the distribution network's length and the number of substations.
- The controllable OPEX may be indexed for inflation by applying the consumer price index or another appropriate indexation method for the reference prices of goods and/or services in question.
- Allocation keys and prices for shared services with related companies should be subject to regulatory monitoring and approval. As a core benchmark, the price of internally procured goods and/or services may not be higher than the market price. If a reference market price is not available or the market does not exist, internally procured items shall be valued and recognized at cost.
- Operating costs related to the assets excluded from the RAB may be approved and included as part of the overall operating costs, if the respective assets are used in regular operation and the DSO is responsible for their repair and maintenance (such as substations or (pipe)lines financed through grants or owned by investors).
- Incidental costs of damages caused by extreme weather or natural disasters are justified costs of operation. Such costs might be provided through the annual allowance for the dedicated budget or through an ex-post analyses and approval of actual costs incurred or alternatively through the recognition of insurance costs.
- *Other revenues* earned by the DSO, in addition to revenues from regulated tariffs and charges, may be recognized as a deductible item in calculation only if the corresponding costs were recognized and included in the total costs.

### 3.3.1 COSTS OF NETWORK LOSSES

Distribution losses are a separate cost category in relation to operating costs.

When benchmarking is used to determine the costs of approved losses, the comparison of the level of losses expressed as a single percentage of electricity inputs may be very deceptive, unless the consumption structure per voltage level is taken into account as losses are increasing at the lower voltage level.

Additional considerations are needed to ensure comparability of data on the levels of network losses, such as delimitation between transmission and distribution at the high voltage (HV)/high pressure (HP) level, transit flows at medium voltage /pressure level, treatment of public lightning and DSO's self consumption.

#### GENERAL REMARKS

- Cost of network losses should be a compulsory factor in long-term cost-benefit analyses of network investments, based on the Lowest Lifecycle Costs Methodology.

- The price of energy losses should be based on the reference market price and should reflect the trends at the wholesale electricity/gas market, allowing the DSO to keep savings if purchase price is lower or bearing the costs if the purchase price is higher than the reference market price.
- Economic incentives to reduce losses should be provided via bonus / malus schemes, allowing the DSO to keep savings from loss reduction and, vice versa, to bear additional costs if the losses are higher than the approved level during the regulatory period.

#### TECHNICAL LOSSES

- Technical losses as a matter of regulatory concern should be recognized not only as a part of costs of service, but also in consideration of increased capital costs incurred as a result of long-term cost optimization of new investments.
- As regards network losses, Article 15 of Directive 2012/27/EU obliges DSOs to a) undertake an assessment of the energy efficiency potentials of their gas and electricity infrastructure, in particular regarding transmission, distribution, load management and interoperability, and connection to energy generating installations, including access possibilities for micro energy generators, and b) identify concrete measures and investments for the introduction of cost-effective energy efficiency improvements in the network infrastructure, including a timetable for their introduction.
- Regulatory measures to decrease technical losses should aim at achieving long-term goals, as investment decisions should be made on the basis of lowest lifecycle cost rather than on the basis of lowest investment cost. This measure is oriented towards the distribution transformers, cables and overhead lines, thereby influencing the long-term design of the distribution network.
- As regards power transformers, the legal basis for their design and procurement is given by Directive 548/2014/EU for implementing the Ecodesign Guideline 2009/125/EG for transformers, obligating the countries to exclusively install power transformers with decreased levels of losses. The changed design logic of distribution cables is likely to decrease the optimal average utilization rate when compared with the conventional approach, as a result of factoring in the losses in optimal design solutions.

#### NON TECHNICAL LOSSES

- Despite the fact that recognition of non-technical losses explicitly conflicts with the principle of cost reflectivity and non-discrimination among customers, a certain level of non-technical losses may be recognized as a transitory measure for a limited period of application, depending on the specific circumstances in each country.
- Regulators should oblige DSOs to continuously decrease the level of non-technical losses with the ultimate target to reach the level of best performing companies.
- Treatment of costs for non-technical losses has to be consistent with the treatment of any subsequent revenues, such as the revenues accrued afterwards from detected illicit consumption. Revenues earned from detected illicit consumption should be recognized as a deductible item only if corresponding costs of losses were recognized as justified costs.

→ The regulatory approach to costs and revenues and consequent allocation of assets and liabilities related to illicit consumption has to be clearly defined in the process of legal unbundling of DSOs from the supply function, preferably assigning both assets and liabilities to the DSO.

#### INCENTIVES TO REDUCE NETWORK LOSSES

→ In incentive regulation, the costs of losses are treated as controllable costs, whereas the level and type of incentives are designed depending on the cause and level of losses.

→ Recognition of the appropriate level of losses should be based on historical performance adjusted by a targeted improvement factor.

→ Incentives for reduction of losses should be provided by allowing DSOs to receive benefits/costs if the actual performance is better/worse than the approved level during the regulatory period, excluding any ex-post revenue adjustment.

→ Once the target level of losses is achieved, the incentive based regulation for loss reduction should be terminated.

→ Any further measure for reduction has to be based on a cost-benefit analysis and overall cost effectiveness of the envisaged abatement measure.

#### 3.3.2 EX-POST ADJUSTMENT

Annual minor revenue adjustments might be performed during the regulatory period to acknowledge changes of the respective parameters in the subsequent year:

- Volume and demand deviations above a certain threshold,
- Inflation index,
- Risk free rate,
- Price of energy losses.

Ex-post adjustment of DSOs' revenues to adjust to the volume variations prevents exposure to non-controllable volume risk. Ex-post revenue adjustment and compensation should be applied with respect to:

- Volume and demand variations,
- Non-controllable costs,
- Quality of service performance under incentive regulation.

#### BASIC REMARKS

→ Ex-post adjustment should be performed to recognize significant difference between the actual and approved amounts of non-controllable OPEX and/or key determinants for tariff setting where appropriate.

→ A sliding scale is recommended for sharing socio-economic benefits related to the actual quality of service performance compared to the targeted parameters.

→ In order to maintain the balance between the principle of tariff predictability and cost recovery, regulatory tools may include the definition of a threshold for adjustment over the subsequent tariff periods.

## 4 INCENTIVE REGULATION

Incentive regulation is an advanced regulatory method or rather an amendment to standard regulatory methods applied for setting network tariffs, which involves targets for DSO's increased productivity and performance.

Incentive regulation should be treated as a set of complementary tools which are applied to resolve key regulatory objectives, such as:

- ✓ Productive /operational efficiency,
- ✓ Allocative efficiency,
- ✓ Quality of service.

These objectives may be conflicting and difficult to achieve, if they are considered separately.

### BASIC REMARKS

- Taking into account the current state of distribution network tariff regulation in the Contracting Parties, incentive regulation is recommended to be introduced in two transitional steps:
  - In the first phase, costs of distribution losses and simple innovation incentives schemes should be introduced;
  - In the second phase, elements of incentive regulation for operational efficiency and quality of service can be incorporated.
- The period between the two steps should be sufficient to provide additional time for preparatory works which are necessary to provide a coherent regulatory framework.
- Regulatory authorities should not seek for claw-back and allow DSOs to retain the efficiency gains during a regulatory period, including operating cost savings under the incentive schemes and the reduction of physical network losses.
- The regulatory period should be sufficiently long to allow the regulated utilities to reach the imposed efficiency targets and thereby to reap benefits until the next tariff setting period. A reasonable length is in the range of four to five years.

### 4.1 OPERATIONAL EFFICIENCY

Incentivizing network companies to reduce costs is more complex for capital expenditure (CAPEX) than for operational expenditures (OPEX). The complexity comes from the distinction that should be made between investments needed to expand the network to support changes in supply and demand for network services and investments needed to meet non-economic objectives such as security of supply. Furthermore, investments' efficiency is difficult to evaluate since the resulting output is typically realized after several regulatory periods from the one in which the costs were made.

#### INCENTIVIZING OPERATIONAL EFFICIENCY

- The lifecycle approach is most appropriate to measure the cost effectiveness of necessary investments.
- If company-specific targets are used, the next step in incentive regulation is to set the reference costs of distribution services. The regulator is expected to establish the reference values of a cost-effective DSO based on benchmarking analyses, with which the respective DSOs are to be compared with. Regulation costs are the main drawback, as the model application requires costly information collection and analysis.
- Efficiency requirements should only be applied on controllable operating costs. They may come in the form of a general target applied to all DSOs or in the form of company specific targets, while a combination of targets is also possible.
- Efficiency targets should be determined on the basis of local and international DSO benchmarking taking into account relevant geographical and network specific variables.
- Incentive regulation should be terminated once a satisfactory level of operational efficiency is achieved having in mind that DSOs are not capable to endlessly increase operational efficiency and at a certain point there is no reasonable purpose to further request DSOs to decrease costs.

#### 4.2 QUALITY OF SERVICE REGULATION

Quality of service regulation should be introduced in parallel with the enforcement of operational efficiency regulation.

Quality of service regulation would not be feasible unless the rate of return is properly addressed and allowed, otherwise implementation of penalty schemes might jeopardize the DSOs' financial stability.

The financial reward/penalty might be expressed as a percentage of the allowed revenue or the allowed rate of return, with ceiling and floor values for monetary adjustment.

#### INTRODUCTION OF INCENTIVES

- Quality of service regulation should be introduced in parallel with the enforcement of operational efficiency regulation.
- It is recommended that quality of service regulation is gradually introduced and moved towards the more advanced methods. Established best practice consists of the following steps:
- At the very initial phase, incentive regulation should be based on System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) parameters. In parallel, guaranteed standards should be introduced to protect individual consumers from excessive outage duration.
- In the next phase, the "Energy not supplied" (ENS) parameter and its value may be introduced in order to properly quantify socio-economic costs of outages.

- In the final phase, when a high quality of service is achieved on average at the DSO level, the “worst served customer” regulation should amend the ENS regulation to properly protect and to guarantee minimum quality to all consumers.
- The Performance-Based Method is the most suitable method for quality of service regulation.

#### IMPLEMENTATION OF QUALITY BASED INCENTIVES

- Quality of service regulation is only feasible when the rate of return is properly addressed and allowed, otherwise implementation of penalty schemes might jeopardize a DSO’s financial stability.
- The principle of ex-post sharing of the benefits of quality of service performance between network operators and consumers should be established.
- Quality of service regulation should be based on the continuity parameters SAIDI and SAIFI during the initial phase of scheme implementation. Accordingly, these indicators are also used for evaluating overall quality of supply in the gas sector.
- Weighting factors for different types of interruptions should be laid down for unplanned interruptions, planned interruptions and interruptions caused by third parties to reflect different costs and responsibilities related to each type respectively.
- If guaranteed standards with consumer’s compensation are applied for a maximum duration of a single outage, those outages longer than the threshold value should be excluded from the quality of service regulation, as there is already an incentive to reduce these interruptions.
- Interruptions caused by exceptional events and force majeure should also be excluded from the quality of service regulation.
- Once an appropriate level of quality of service is achieved, as assessed by the regulator, incentive regulation should be reconsidered with respect to the adjustment of targets.

#### 4.3 INNOVATIVE INCENTIVES

A specific regulatory mechanism for innovation, research and development promotion (R&D) through dedicated annual funding is appropriate to incentivize DSOs to undertake such activities.

Innovation incentives may be introduced through simple and inexpensive pilot models in a first phase, gradually increasing the complexity and funding allowance.

Incentives for innovation are provided by allowing for a dedicated R&D budget for both the capital and the operating expenses, whereas any capitalization of the R&D costs in the RAB must be reflected in corresponding revenues.

#### INCENTIVIZING INNOVATION

- From the regulatory and consumers’ perspective, it is reasonable to allow financing through ad-hoc schemes for R&D projects up to the moment when the technology deployment has surpassed the pilot phase and becomes commercially viable.

- Innovation could be incentivized either by setting the rate of return on capital high enough for extra risk in innovation investments or by applying a specific ad-hoc scheme.
- Once the promoted technology becomes commercially viable and mass deployed, it should be treated as any other DSO investment.

#### 4.4 INVESTMENT MONITORING AND INCENTIVES

In general, regulatory competences related to investment activities are defined by law.

Productive efficiency, as a main regulatory goal, may also be applied with regard to investments as the utility is expected to invest in new and existing assets at the lowest cost.

Regulatory challenges under rate-of-return regulation are related to the overinvestment effect and the possible occurrence of underinvestment under certain circumstances such as a low level of regulatory certainty, a low rate of return and low level of tariffs, not providing cost recovery. The regulators' inconsistency can also lead to underinvestment under rate-of-return regulation.

##### *REGULATORY ASSESSMENT*

Regulatory assessment may be performed regarding the investment prudence and the "used and useful" concept. Prudent means that investment fulfils the cost-effectiveness criteria, while "used and useful" means that a facility is actually used to provide services and that it is contributing to the provision of services. However, DSOs should establish their own methodology to evaluate planned investments regarding their feasibility, contribution to network security, quality of supply impact and non-economical criteria assessment.

A lack of clarity in the definition of prudence tests as part the RAB valuation process may also cause utilities to postpone or even cancel some investments.

Investment recovery and stimulus for new investments should be provided through:

- Stability and predictability of the regulatory framework,
- Fair rate of return on investments,
- Achievability of the regulated rate of return.

Regulatory approval of DSOs' network investment plans is an efficient regulatory tool when the DSO is part of a vertically integrated company, otherwise regular monitoring of the investment activities against the planned costs and objectives might be sufficient.

##### INCENTIVES FOR INVESTMENTS

- Return of investment, network expansion and reconstruction should be ensured via a consistent depreciation policy and appropriate allowed rate of return.
- Regarding the investment plans, regulatory focus should be oriented towards performance outcomes related to security of supply, continuity of supply and voltage/pressure quality.
- The achievability of the rate of return should be reasonably provided. Overambitious and lengthy operational efficiency schemes should therefore be avoided.
- As long as the performance indicators are improved in line with the regulatory targets, regulatory authorities should refrain from interfering in the DSO's investment activities.

- Investment decisions should be made with due respect to the lowest lifecycle cost, taking into account the sum of all upfront, recurring and non-recurring costs over the full lifespan of an asset.
- The criteria for recognition of investment costs should be based on cost effectiveness, security of supply and quality of supply parameters, but should also include other non quantifiable energy policy objectives such as social cohesion in general and (within local communities) environmental protection, energy efficiency and other energy policy objectives.
- The criteria applied by regulatory authorities to evaluate the prudence and reasonableness of an investment and the corresponding costs have to be known in advance and applied only if known at the time when the investment decision is made.

## 5 COSTS ALLOCATION AND DESIGN OF NETWORK TARIFFS

Distribution service tariffs can be grouped into five main types:

- Connection fee (€/kW or €/m<sup>3</sup>/h) or (€) for new connections,
- Demand – capacity charge (€/kW or €/m<sup>3</sup>/h),
- Volumetric (or energy-based) variable charge (€/kWh or €/m<sup>3</sup>),
- Fixed charge (€/metering point per month),
- Reactive energy charge (€/kVArh).

The appropriate structure of charges for distribution services is usually not based purely on the technical and economical parameters of the distribution services but also takes into account the administrative costs, feasibility of pricing system implementation, social acceptance, consumer protection, etc.

As a general observation, residential consumers do not accept complex solutions as they do not show much interest in the electricity or the gas bill structure and they expect the pricing model to be simple and easy to understand. They also expect to have predictable electricity and gas bills, provided in a comprehensive and understandable manner.

As there are a number of underlying principles of tariff design, a reasonable trade-off is needed for conflicting objectives.

### PRINCIPLE REMARKS

- Tariffs charged to customers should be cost reflective in a way that they reflect the costs associated with the use of the system in a fair way and that the pricing system is understandable for the targeted customer category.
- Tariff design is expected to provide revenue stability, particularly in a situation where load forecasting becomes more difficult due to the fast deployment of new technologies resulting in a change of consumers' load profiles. The degree of certainty with respect to being able to recover the costs of network services in full is a critical issue from the utilities' perspective.

- Distribution network Time-of-Use (ToU) tariffs should not counteract the price signal of transmission / transportation tariffs and energy supply ToU prices, as they should be fully aligned in order to avoid opposite or conflicting signals for consumers.
- Tariff design and tariff rates can also serve as a regulatory and policy tool to influence investment decisions of network users as regards energy efficiency, demand response and distributed generation.
- Tariff design should be flexible to allow for the adjustment of network tariffs to a changing environment, give more confidence to network operators as regards their cost recovery and balance conflicts of interest of DSOs and connected prosumers.
- Network use tariff design should not have distortive effects on energy efficiency programmes and heating fuel price parity, should take into account protection of vulnerable consumers and should not encourage disconnection of the prosumers with storage facility.

### 5.1. ALLOCATION OF NETWORK DEVELOPMENT COSTS

Use-of-network tariffs and connection fees should be addressed together as the level of connection tariffs directly influences the DSO's revenue that is recovered through the use-of-network tariffs.

The Deep Connection Charging Method is commonly applied as a safeguard to minimize stranded costs of unused network facilities, at the same time applying fair charges to connecting users with the view to cover marginal costs that result from their connection to the distribution network. According to this method, network users pay all costs associated with their connection, including the cost of physical connection to the grid and any upstream grid reinforcement costs. Under the alternative model, the Shallow Connection Charging Method, network users pay only for the cost of equipment needed to make the physical connection to the grid. Costs of reinforcement are borne by the DSO. A mixed approach is also possible where network users contribute to a proportion of any upstream grid reinforcement costs.

Depending on the connection charging regime and the level of connection fees, DSO's remaining revenue is recovered through the use-of-network tariffs.

#### CONNECTION CHARGES

- The share of network development costs to be recovered from connection charges should be fairly set at the level necessary to maintain the underlying purpose.
- Change of the approach to the connection charges should be undertaken only exceptionally, as it undermines the fair allocation of costs for the use of the network between old and new customers.
- Consumers' contribution to the overall network development costs should be provided through variable connection charges, depending on the contracted capacity.
- When the deep connection method is applied, new network users may be charged only for a fraction of the existing network upgrade costs, in proportion to their marginal contribution to the capacity of the upgraded network facility.

→ Connection charges related to individual facility connection are recommended to be standardized for specific consumer classes, at least for consumers connected at the low voltage network or low pressure gas pipeline.

## 5.2 ALLOCATION OF USE OF NETWORK COSTS

Tariff design consists of two processes: identification of cost drivers and identification of customers with the same or similar costs.

Traditionally, distribution network tariffs are predominantly based on the volume of delivered energy. On the other side, costs of distribution services are mainly driven by capacity and only a minor portion of costs is driven by the energy delivered.

In addition, protection of customers, in particular vulnerable customers and those in remote areas, allows positive discrimination and trade-off between the principles of cost reflectivity and social cohesion. Uniform tariffs or preferential rates are used to reconcile such seemingly conflicting policy objectives.

### GENERAL REMARKS

- The bill must be easy to understand and its structure should be kept as simple as reasonably possible.
- Recovery of DSOs' fixed costs should be based on a well-balanced application of fixed, volumetric and demand charges.
- The tariff system has to be flexible to adjust to the dynamic evolving environment when a number of tariff components and different levies and taxes are likely to be changing.
- In the light of constraints stemming from practical considerations, such as existing and planned metering infrastructure, billing systems and social acceptance, the granularity of the tariff system should be limited.
- Geographically uniform network tariffs are recommended only when an inter-DSO compensation scheme is administratively and economically feasible.

## 5.3. TARIFF STRUCTURE

Cost allocation is the process of apportioning a DSO's costs between and within consumer classes. There are three main methods used for cost allocation, known as "marginal" cost, "incremental" cost and "embedded" cost.

The key cost drivers are the connected capacity, the delivered energy and the number of customers or connection points. At the same time, customers are classified into groups depending on the costs attributable to their pattern of network use.

The vast majority of distribution system costs are capacity driven and associated with constructing, maintaining, upgrading and replacing the existing physical infrastructure. In that sense, these costs are fixed irrespective of the quantity of distributed electricity or gas.

Only a minor share of costs are variable costs, usually based only on distribution grid losses.

However, the distribution tariff structure does not explicitly allocate fixed and variable costs to corresponding fixed and variable network charges.

## IDENTIFICATION OF COST DRIVERS

- The dominant part of network costs is fixed and inherently attributable to connected or peak capacity.
- The energy component depends on consumption and shall, as a minimum, cover the cost of marginal losses (the loss that occurs when one extra kilowatt-hour or m<sup>3</sup> is taken out, at a given load) in the network.
- The customer-specific costs are related to the metering, billing, collection and customer support services and attributable to the number of customers and/or number of customer connection and metering points.

## ALLOCATION OF COSTS TO CUSTOMER CATEGORIES

- A DSO's total costs should be classified as demand-related, energy-related and consumer-related per each voltage / pressure level in order to make cost reflective allocation.
- Costs allocated to lower voltage / pressure levels should be calculated as the cascading cumulative costs, which include the costs of higher voltage / pressure levels that are used for electricity / gas delivery.
- DSOs should be obligated to allocate all costs to the corresponding voltage/pressure levels to the extent feasible.
- Costs not attributable to the specific voltage/pressure level should be allocated to the voltage/pressure levels using predefined allocation keys.
- For large industrial and commercial consumers, the attributed capacity is calculated on the basis of the consumers' measured individual peak demand, non-coincident to system peak demand. The contribution to overall system peak demand is incorporated through the coincidence factors at the class (customer category) level.
- For households and small commercial consumers, the demand charge is usually based either on the individually contracted capacity or on the average employed capacity within the customer category, unless the smart metering roll out is completed and metering infrastructure allows individual peak demand to be measured. Whichever method is applied, the contribution of the individual consumer and consumer category to the system peak demand should be reflected through the relevant coincidence factors that recognise statistical contribution to the system peak demand.
- A contribution to coincident and non-coincident peak demand should be factored in the calculation and allocation of costs to be recovered through demand charges from each consumer category's contribution to the relevant peak.

## 5.4. TARIFF DESIGN

In several countries, overall tariff design is defined in a specific rule, commonly known as the "tariff system". These rules define the system of charges and classification of customers into categories or so-called "tariff groups".

The key regulatory challenge regarding the cost allocation is to set an optimal share of fixed costs to be recovered through the capacity or demand charges, with the aim to improve the fairness and equality in cost recovery as they reflect the peak-demand driven nature of distribution system costs.

Demand charges also provide incentives for consumers to reduce peak demand and to implement demand side measures through installation of storage devices and smart appliances, hence reducing demand from the electricity network, or from the gas network, when applicable. However,

there are applicability concerns, as the price signals of cost reflective tariffs may not be understandable to small consumers and those consumers without a proper metering system.

In addition, cost reflectivity may be distorted without correct data, particularly in a dynamic, changing environment.

#### DESIGN TOOLSET

- A demand charge recovers a portion of the allowed revenue through a tariff component that is based on the customer's measured / registered maximum demand for electricity (in kilowatts) or gas (in kilowatt-hours/hour or m<sup>3</sup>/h).
- The weight of demand charges in the tariff structure should be gradually increased to reach an optimal balance of cost reflectivity and revenue recovery on the one side and energy, environmental and social policy goals on the other side.
- Periodic, usually monthly, fixed charges should be set at a level of the customer-specific costs related to the metering, billing, collection and customer support services and should not exceed the costs attributable to an incremental customer.
- Remaining DSO revenues should be recovered through the volumetric component of the network tariffs. The energy component depends on consumption and shall at minimum cover the costs of marginal losses in the network.
- For customers with a proper load registration, the maximum demand for billing purposes can be defined as the maximum demand during a period that is coincident with the system peak, maximum demand during a period that is coincident with the consumer class peak, maximum demand based on the consumer's own peak during the month or simply as a consumer's contracted capacity.
- For residential and small commercial consumers, introducing a demand charge based on the measured peak demand might be gradually implemented, depending on the roll-out of smart meters. For these customers demand charges may be based on the contracted capacity with a power / gas band pricing scheme, allowing consumers periodically, but not seasonally, to change the contracted capacity.
- A reasonable approach to ensure cost reflectivity is to offer to customers without load registration a Time of Use (ToU) volumetric tariff as a default pricing option, preferably without opt-out possibility to revert back to a flat pricing model.
- For demand side management measures to be unlocked, there is need to have a more complex tariff structure with the ToU differentiation depending on the season and/or time of day. Otherwise, customer response and consequently load shifting is hardly to be expected on a large scale.

## 6 DISTRIBUTED ENERGY RESOURCES

The model of specific rates for Distributed Energy Resources (DER) is considered optimal with the gradual introduction of new DER consumer subclasses once the level of deployment is sufficiently high.

The inevitable complexity of DER tariffs faced by consumers should be reflected through relatively simple pricing models to the extent possible; however the rates for aggregators can be more complex and granular to properly reflect the value of services.

## TARIFFS FOR PRODUCERS [G-CHARGES]

- Energy and capacity based G-charges should not be applied on distribution level.
- Reactive energy consumed by power plants while generators are in operation should not be charged.
- Locational generation signals should be provided on a cost-reflective basis through an appropriately designed deep connection charging regime with restrictions related to the grid reinforcement cost sharing.
- New power plants should not be charged for the full costs of grid reinforcement but only for the additional marginal costs that are cost-reflective to their marginal contribution to the power system capacity.

## FAIR CHARGING WITH LONG TERM PERSPECTIVE

- Tariff design with respect to the tariff components should be timely adjusted to appropriately reflect the costs to be faced by each subclass of consumers with the installed DER, as well as the revenues they receive for the grid services provided.
- Prosumers should be charged for the distribution services on the basis of capacity tariffs reflecting the fixed network and system costs and volumetric tariffs which reflect the variable network and system costs.<sup>1</sup>
- Tariff rates for electric vehicle charging stations should incentivize car charging when energy costs are low during the off-peak period. Time-of-Use default rates for this class should be obligatory, with the introduction of an additional "critical peak" pricing period if technically feasible.
- The new pricing model to incorporate DER consumers should be mandatory without opt-out option to revert back to the previous rate structure.
- DER services should be remunerated only if they are requested by DSOs and contractually agreed between the parties.
- Remuneration should only reflect DER services that are related to the distribution network operation.

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<sup>1</sup> For more information please refer to EnC [Policy Guidelines 01/2018-ECS on the grid integration of prosumers](#) .