Energy Community


# Technical Assistance to Develop Policy Guidelines for the Distribution Network Tariffs

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Final Report

# Technical Assistance to Develop Policy Guidelines for the Distribution Network Tariffs

Submitted by:
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# Contents

# FOREWORD

This Report is prepared in accordance with the Contract for the "Provision of Technical Assistance to Develop Policy Guidelines for Distribution Network Tariffs", signed on July 17th 2017 between Energy Community Secretariat and Mr. Dalibor Muratovic (Consultant).

Scope of work is defined by **Section 1: Service specifications, paragraph 3.1.1. Project description.**

*''3.1.1. Project description*

*In an initial assessment conducted by the Secretariat, the claims of the affected DSO indicated the following (non-exhaustive) issues appeared as potentially problematic:*

*1. Costs recognition and recovery of justified costs*

- *Recognition and valuation of assets necessary for viable operation;*
- *Recognition of the level and cost of network losses;*
- *Justification and incentives for investment in network;*
- *Recognition of costs of service provided by related parties;*
- *Assessment of fair return on assets and return of assets.*

*2. Incentives*

- *Incentive mechanisms to cost efficiency and overall cost effectiveness of the operation;*
- *Quality of service standards and recognition of corresponding costs;*
- *System balancing, demand-side response, flexibility and integration of distributed generation.*

*3. Costs allocation and design of network tariffs*

- *Network structure and design;*
- *Network development plans;*
- *Allocation of network development costs: connection and usage;*
- *Terms and conditions for connection and connection costs;*
- *Classification of costs components;*
- *Allocation of recognized costs of operation on components: capacity, volume, customer, other.*

*The above list is not exhaustive and the Contractor is free to include evaluation and position on other instances relevant from the point of view of network operator and of network users. ''*

Further consultancy tasks are given by paragraph **3.2. Specific work:**

*''The TA Provider shall perform the following tasks:*

*The expert shall submit Report covering the issues of concern listed in Part 3.1.1 Project description and any other current or emerging issue of concern relevant for this exercise to be identified by him/her.*

*The report will have two parts:*

*i) Assessments of the problematic issues, possible solutions and evaluation of each solutions (viability, risks and advantages)*

*ii) Recommendation of procedural and substantial dealing with the issues of concern, including:*

- *elaboration of criteria for evaluation and recognition of costs component of concern,*
- *introduction of incentive based tariffs, with the focus on quality based incentives challenges and best*
- *allocation of costs component and tariff design.*

*The Consultant shall also comment on primary and/or secondary legislation, where relevant.''*

Beside the list of issues provided by Project description, this Report also covers additional relevant instances as follows: Choice of optimal regulation model taking into account specific cost category, Innovation incentives, Integration of distributed energy resources, Network tariffs for producers – ‘’G’’ charges, Future regulation challenges and other minor complements that were needed to provide a coherent set of recommendations regarding the Distribution Network Tariffs.

# 1 INTRODUCTION

According to EU legislation (Directive 2009/72/EC[1]), national regulatory authorities are to ensure that distribution tariffs are non-discriminatory and cost-reflective, taking into account the long-term, marginal, avoided network costs from distributed generation and demand-side management measures.

In addition, the directive further states that distribution tariffs should be sufficient to allow the necessary investments in the networks to be carried out in a manner allowing these investments to ensure the viability of the networks.

Concerning the DSO tariffs and overall efficiency, Article 15 of the Directive 2012/72/EU[2], incorporated into the Energy Community acquis, prescribes that:

*"Contracting Parties 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".* Furthermore, 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"*. In addition, it is stated *"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".*

Distribution network tariffs are in the competence of the EU Member States and Contracting Parties, allowing each of them to develop its own network tariff methodology.

In the economics literature, industries like the electricity distribution or transmission are known as natural monopolies. The primary purpose of economic regulation is to prevent the monopolist to overcharge customers and to stimulate an effective management resulting in productivity development and optimal quality of the services.

There are several methods of economic regulation of natural monopolies such as: rate of return, price cap, revenue cap, yardstick regulation with the benchmark elements, performance standards etc., whereby combination of these methods may be applied too. General trend in regulation of electricity distribution activities is a changeover from a return-on-capital-regulation to more sophisticated incentive-based regulation.

Beside the different methods applied, current regulatory models also differ with regard to the most important parameters of tariff setting.

[1] Directive 2009/72/EC concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC

[2] Directive 2012/27/EU on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC

Common feature of all regulatory models is the division of costs related to capital costs and operating costs. The capital costs are directly linked to the value of assets which are used to provide utility's services, while the operating costs are divided in controllable and non-controllable operating costs.

The two main steps in designing network tariffs are the calculation and approval of total revenue requirement and the allocation of that revenue to system user's classes. The regulator has to determine the utility's asset base to set depreciation and reasonable cost of capital, which summed up with allowed operating costs make total allowed revenue.

The regulators have a complex task to regulate distribution companies whose size may vary from very big company serving millions of consumers to many small companies serving a couple of thousand consumers. To add to the complexity, the distribution services are also provided in different environments regarding geography and climate.

Whichever method is applied, it is expected to constrain the regulator's discretion in setting prices and to provide investors with long term warranties that invested capital is going to be paid back with reasonable rate of return. Proper regulation method that lowers investor risk directly impacts and lowers the cost of capital too.

# 2 OVERVIEW OF THE INTERNATIONAL PRACTICES

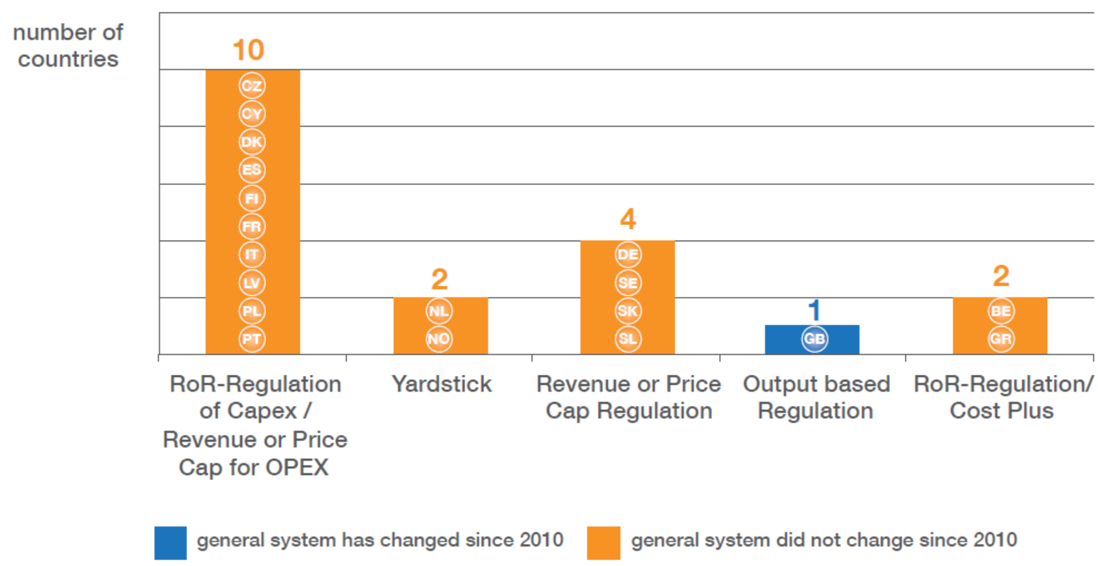
## 2.1 TARIFF METHODOLOGIES

Regardless of the regulation method applied, regulator has to set allowed revenue that is usually based on the utilities' past performance in the base year. The base year is in principle defined as the last complete financial year at the moment of regulatory tariff review proceeding. The cost situation in the base year is therefore crucial for determining allowed revenue for the following regulatory period.

Some of the regulators in Energy Community Contracting Parties (EnC CPs) still apply rate of return regulation for the distribution tariffs setting. This is the case in Bosnia and Herzegovina, Serbia and Ukraine. Kosovo*[3], FYR of Macedonia, Montenegro and Moldova apply revenue cap regulation method. Georgia applies combined methodology based on revenue cap regulation methodology with incentive regulation used for controllable operating expenses. In Albany, price-cap regulation method with efficiency targets is applied.

Rate of return method, also known as a cost-of-service or cost plus regulation, is based on a simple principle of compensating the regulated utility for its recognized cost. This method had been applied for a long time since the price regulation commencement, but has been recently replaced by the more sophisticated methods with various forms of incentive regulation.

EURELECTRIC in its analyses of investments and regulatory framework in 18 EU Member States conducted a survey of electricity distribution regulation methodologies applied in 2014[4], summarizing the regulation methods into five main types, as shown in Figure 1.




Source: EURELECTRIC

**Figure 1** *Regulation methodologies in Europe*

[3] This designation is without prejudice to position on status and is in line with UNSCR 1244 and ICJ Opinion on the Kosovo declaration on independence

[4] EURELECTRIC, Electricity Distribution Investments: What Regulatory Framework Do We Need, p. 9

As shown in Figure 1, pure rate-of-return regulation method is almost abandoned in Europe, except in Belgium and Greece.

Specific solutions are found in Netherlands and Norway where regulators apply yardstick regulation in combination with the efficiency incentives and in Great Britain where performance-based methodology is applied.

The main shortcomings of the rate-of-return regulation are possible failures to meet main regulatory objectives, as it does not incorporate explicit incentive to improve cost efficiency or to increase quality of supply (QoS). Under rate-of-return regulation the risk of capitalizing OPEX is widely observed as the utility prefer capital to operating costs thereby generating overinvestment effect.

Revenue-cap regulation requires the regulator to set maximum allowed revenue that is partially or totally linked to its regulated costs, to be applied for price setting during a specified time period. As a part of regulation method, some regulators set inflation index (usually Retail Price Index - RPI) and an assumed rate of productive efficiency factor (X), thus allowing adjustment of the maximum allowed revenue for the inflation rate and expected efficiency savings.

Majority of European countries base their regulatory framework on the Regulatory Asset Base (RAB) concept, where specific solutions are applied in Germany and Spain[5]. German regulatory model is based on the benchmarking of similar operators, where the total allowed revenue is a sum of three types of costs: inefficient, efficient and non-controllable. Spain applies a reference network model as a technical comparison tool for electricity distribution tariffs setting.

The concept similar to the RAB is applied in the USA where the ‘’rate base’’ approval model is in use, usually including the condition related to the “inefficiently incurred” costs exclusion from the asset base.

***Regulation method in use generally reflects the specificities of each country with regard to the power system structure, number and size of DSOs, maturity of regulatory framework and other country inherent characteristics.***

## 2.2 PRICE SETTING PERIOD

Price setting period is a preset period during which the prices for network services will be predefined, with possibility to perform minor adjustments to reflect changes in some input parameters.

It is generally accepted that price setting period (regulatory period) is in the range 3-5 years, in some cases even longer. Nevertheless, tariff review procedure may be reopened by the regulated utility or by the regulatory authority on its own initiative during the regulatory period under certain conditions.

The regulator may decide to update the data and revenue caps every year and set yearly revenue, or alternatively regulator sets all parameters at the beginning of the regulatory period and adjust these only at the end of the period.

However, minor adjustments can be carried out continuously over the regulatory period, e.g. taking into account RAB changes, yearly changes in RPI, interest rate on government bonds if used for

[5] E&Y, Mapping power and utilities regulation in Europe, p. 9, 11

determination of the Weighted Average Cost of Capital (WACC) and changes in power prices used to calculate costs of distribution losses.

RAB annual adjustment is a standard regulatory practice in the majority of EU Member States[6], applied to incorporate changes related to the inflation, capital expenditures, depreciation, disposals and customer contributions during the regulatory period. If the adjustment is provided, it is referred to as the roll forward method. Other option is to set all RAB parameters at the beginning of the regulatory period to be applied throughout the price setting period, as it is for example provided in Serbia where the value of the regulated assets is calculated as the arithmetic mean of the opening and closing values in the regulatory period.

***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. Regulated undertakings also perceive positive correlation between longer regulatory period and regulatory stability, as longer period gives them certainty against significant changes in regulatory framework.***

[6] CEER, Report on Investment Conditions in European Countries, p. 139-141

# 3 COSTS RECOGNITION AND RECOVERY OF JUSTIFIED COSTS

DSO's costs of service are categorized as the capital costs linked to the value of regulatory asset base and operating costs. Capital costs are sum of the depreciation costs and return on employed assets, while operating costs may also include costs of network losses, or alternatively losses may be treated as a separate cost category. All categories of costs are subject of regulatory evaluation and recognition, as only the justified costs might be approved and recovered through the network tariffs.

Total required revenue is consisted of the allowed capital costs, operating costs and cost of losses, deducted by the DSO's other revenues. In addition, total revenue might be adjusted for the amount of the excess/deficit revenues during the previous regulatory period.

## 3.1 CAPITAL COSTS

### 3.1.1 Fixed assets, recognition of assets necessary for operation

In the electricity distribution sector, significant part of revenue requirement is related to the capital costs and depends predominantly on the valuation of the regulatory asset base through its depreciation and the rate of return. Both depreciation (DEPR) and return are derived from the RAB, applying assets' depreciation rates and average rate of return (RoR)

Capital costs (CAPEX) by its definition are expenditure on investment in long lived network assets, such as underground cables, overhead electricity lines and substations etc.

For determination of required revenues of a DSO, the total capital costs may be expressed using the simple equation, as the following one:

CAPEX= DEPR + (RoR * RAB)

#### *3.1.1.1 Regulatory Asset Base concept*

The Regulatory Asset Base concept was developed in Great Britain to provide assurance to investors in privatized network utilities by setting out the principles for the calculation of price caps. The RAB model was developed to value existing assets as a part of the privatization process, but the model does not preclude any particular form of ownership.

The concept of RAB is intended to provide the full recovery of investor's capital investment with fair level of return. This way, RAB serves as a safeguard to the investors, especially in privatized network utilities, as it protects their investments not to be treated unfairly.

In the meantime, the RAB model has become a prevailing model in regulating natural monopolies in electricity sector which is applied to assess the value of the assets used in the performance of a regulated activity.

The issue whether the RAB should be a forward looking or a backward looking concept is arguable. It is generally assumed that efficient regulation should mimic the effects of a perfectly competitive market. In such a market, assets are worth what they are able to produce when efficiently operated during the life time as expressed in the net present value of expected benefits earned. In this case RAB has a forward looking perspective.

On the other side, an original asset that was financed by issuing debt is repaid out of revenues (which include depreciation of the historic cost) until the asset is written off, thereby RAB valuation is a backward-looking concept. Where there is no competitive market, such as electricity distribution, sustainable solution should be backward looking, as any forward looking valuation would require regulator to decide what the asset would be worth with regard to the future revenues which are also set by regulator, thus causing an obvious circularity between RAB value and future revenues. Similarly, if RAB is considered to be a forward looking concept, assets impairment assessment would also cause circular reference of discounted future cash flows from the assets utilization and the assets value.

RAB concept is applied to provide financial capital maintenance, to avoid eroding the capital value if the revenues are insufficient to cover depreciation and earn a normal rate of return.

RAB as a regulatory commitment device is also recognized as a strong tool to resolve time inconsistency problem[7], which arises if governments and regulators have powerful incentives to drive the prices of assets down heavily, so that current consumers pay prices reflecting only short-run marginal costs. Time inconsistency problem is recognized as a fundamental economic problem that arises from the enormous gap between marginal and average costs. This problem is resolved by an agreed valuation of old assets and reasonably acquired new assets.

Thereby, as a consequence of stable regulatory framework that protects investors from possible expropriation, cost of capital is sustained at the low level and the regulated company has little difficulty in raising new finance (equity or debt) at moderate rates. Consequently, RAB concept application has a direct positive impact on the level of retail electricity prices, as a result of lower cost of capital.

#### *3.1.1.2 Regulatory Asset Base structure and value*

RAB includes the set of assets necessary to carry out the business functions, while the monetary value given by regulator to represent the RAB is referred to as Regulatory Asset Value (RAV). The monetary value is given as a carrying value.

In theory, the assets to be included in the RAB have to pass the prudency test, but when electricity distribution is considered, it makes no sense to assess the fair market value or income generating capability of an individual asset. It is more appropriate to determine the value of a cash generating unit, comprised of a group of individual assets. It would also be practically impossible to perform regulatory assessment whether each investment is a prudent one, having in mind yearly number of individual investments. Prudent investments are generally the investments which would have been made by efficiently operated DSOs, based on the information which had been known or should have been known to a responsible competent management at the time the decision was made.

Besides the tangible fixed assets in use as a dominant part of RAB, RAB can include the working capital, intangible assets and the assets under construction, depending on the regulatory framework in specific country. Detailed information about RAB structure in EnC CPs is provided by the Energy Community Regulatory Board (ECRB) study ''Status Review of Main Criteria for Allowed Revenue Determination'', published in 2013[8].

[7] Dieter Helm, The Draft Water Bill, p. 15

[8] ECRB Status Review of Main Criteria for Allowed Revenue Determination for transmission, distribution and regulated supply of electricity and gas

**Table 1.** *Regulatory asset base structure in EnC CPs*[9]

| | ALB | BiH | MKD | GEO | KOS* | MNE | MDA | SRB |
|---|---|---|---|---|---|---|---|---|
| Intangible assets | X | X | X | X | | X | X | X |
| Working capital | X | X | | | | X | X | |
| CWiP | X | X | X | X | X | X | | X |

*Source: ECRB and Tariff setting methodologies in respective countries*

Intangible assets are assets without physical form including patents, trade marks, software, license and other types of intangible assets such as goodwill. Goodwill is incurred only when network company is acquired by another entity, and its value is defined as a difference between the purchase or market price and net carrying value of tangible and intangible assets acquired. Goodwill is not subject of amortization, but should be regularly valued to determine if impairment is needed.

Setting the RAB value is one of the most difficult and critical aspects of regulatory price setting, because the valuations cannot be related to competitive market. Choice of the asset valuation methodology could have significant implications on the RAB, the maximum allowed revenues and consequently the final end user's prices.

The common cost based methodologies used for the RAB valuation are: Historical or Original Cost Approach (HC), Indexed or Trended Historical Cost Approach (IHC), Replacement cost (RC), Depreciated Optimal Replacement Cost (DORC).

There are also value based methodologies that determine the value of an asset largely from its cash generating capacity measured either by the net present value of future cash flows or by the cash generated by selling the asset. The net present value of future cash flows is not appropriate for regulated business, as the future cash flow directly depends on the asset base value. Apparent circularity would occur in these cases between the asset base valuation and the future cash flows. If the fair market value for network assets can be established, i.e. if such a market exists, the RC should be compared against such fair market value.

Each methodology may be assessed in terms of economic efficiency, practicality, consistency, cost of implementing and fairness. Selecting an optimal method strongly depends on the specific weight given to each criterion of evaluation.

**HC Method -** RAB is set equal to the depreciated original cost or net book value of the assets, based on the original historic costs of acquisition disclosed in financial accounts. Main advantages of this method are transparency, simplicity and absence of subjective judgment, but it fails to send economic efficiency signals as the value of assets is not adjusted in terms of inflation and technological advances. Due to the lack of value adjustment, this method tends to underestimate the value of the assets and provides insufficient return to the company in times of high inflation, thereby not providing adequate funding of

[9] Data for Ukraine were not available

new investments. On the contrary, the assets may be overstated if technology is being more mature and cheaper.

This method is not adequate where accounting and property records are not reliable, particularly for assets with long useful life, as is the case for most of network structures.

HC method avoids discussion between utilities and regulators as the values are provided from the audited financial records, the administrative costs are lower since it does not require any additional expertise to determine the value. With regard to the cash flows, it provides a continual matching between the money the shareholders provided for investment and the revenues that are provided through the tariffs.

**IHC Method -** This method calculates the assets value on the basis of the assets value in the previous year updated for annual investments and depreciation, indexed for inflation, measured as the consumer price index or other industry specific index. This methodology corrects the lack of RAB inflation adjustment under the HC method. On the other side, there is no guarantee that the simple inflation indexation will lead to setting a fair value of the assets equal to their respective market values.

**RC Method** - This method calculates the assets value based on what it would cost to replace them at current prices, thus providing cash flow to finance network replacement costs. It has advantage of being able to overcome deficiencies of poor accounting records. The main disadvantages of RC method are that it entails a degree of estimation and judgment, while the administrative costs are higher. Application of this method also requires the considerable input in terms of manpower, from engineers and accountants as well. Additional disadvantage is that it provides to investors cash flow that is different from what they had paid for investment originally. On the other hand, assets valued at RC provide investors certainty that fully depreciated assets may be replaced with new assets from the accumulated depreciation.

**DORC Method** - It measures the cost of replicating the service potential in the most efficient way possible (from an engineering perspective) whilst correcting for the service life of the asset which has expired. It removes any inefficiency that exists in the RAB's current assets configuration, providing efficient pricing signals. Main disadvantage is complexity in implementation, as it requires considerable input of expertise and administrative financial costs. It also requires a degree of subjective judgment about the optimum configuration of assets in the RAB and about the optimization of other parameters.

An overview of assets valuation principles prescribed by the tariff setting methodologies in respective EnC CPs is provided in Table 2.

**Table 2.** *Overview of assets valuation principles*

| Contracting Party | Valuation principles |
|---|---|
| Albania | HC with revaluation option |
| Bosnia and Herzegovina - Republic of Srpska | RC |
| Bosnia and Herzegovina - Federation Bosnia and Herzegovina | HC with revaluation option |
| Georgia | HC with revaluation option |
| Kosovo* | IHC |
| FYR of Macedonia | Revaluation |
| Moldova | HC with revaluation option |
| Montenegro | IHC with revaluation option |
| Serbia | Revaluation |
| Ukraine | Revaluation |

*Source: Tariff setting methodologies in respective countries*

A RAB valuation methods analysis in EU Member States reveals that only three methods are applied by the regulators (RC, IHC and HC). RC method is frequently cited as the best method probably because the practicality criterion has more weight than other evaluation criteria[10]. It is important to emphasize that combination of those methods may also be applied in order to provide the optimal and the most objective valuation results.

As an example of combination of different methods, Germany applies the method that differentiates treatment of fixed assets acquired before 1 January 2006 and after this date. The assets are thereby differentiated depending whether they were commissioned before or after the regulation commencement date, as follows:

- For assets acquired before 2006 the imputed depreciation is calculated for the portion of the assets funded by equity using the replacement cost asset valuation method. Depreciation for the portion of the assets funded by debt is based on historic cost. In this way the regulated company can collect sufficient equity over the asset life to finance the asset replacement without increasing the debt level, i.e. the gearing remains constant over time. The compensation for inflation is provided on the asset side for the portion funded by equity, thus allowing the real rate of return on equity and nominal return on debt.
- The financial capital maintenance is applied for assets acquired after 31 December 2005 using depreciation based on historic cost. The inflation is compensated in the allowed nominal rate of return on equity and debt.

[10] IERN, Overview of European Regulatory Framework in Energy Transport, p. 17

Germany has capped the maximal allowed equity ratio for regulatory purposes at 40 %. The portion of equity necessary for operation in excess of 40% is treated as debt.

Similar example is provided in Denmark where the investments that had been made before the 2000 are valued using the replacement value given by the unit investment costs, while the investments after the 2000 are added to the initial regulatory assets base with the actual investment costs.

Historical cost method is currently applied in 9 out of 23 EU Member States and Norway, while the RAB amount is exclusively based on the revalued assets in only 4 countries[11]. Other countries apply combination of these methods. Revaluation of assets in Belgium, Czech and Finland has caused significant deviations between the RAB defined in net book values and the RAB based on the revaluation of assets (RAB increased 50%, 74,5% and 54% respectively[12]). In Sweden the RAB value for the regulatory period 2012-2015 had increased by app. 38%, as a result of the valuation methodology change[13].

Generally speaking, investors should be provided by some form of compensation for assets or capital devaluation through inflation, in order to keep resources for long run operation, since the new investments have to be paid for in the present values and must be partly financed by revenues received in the past.

Inflation compensation can in principle be achieved through the application of assets replacement costs method, inclusion of indexation in RAB (IHC method) or by applying nominal rate of return in the regulatory schemes. If the inflation compensation is already performed through the RAB valuation process, it allows real rate of return to be used. Which method is to be applied depends on the regulatory assessment, considering specificities of each country.

Specificities of the EnC CPs regarding the assets records are: historical asset evidences may be missing, unreliable, different forms of organizational changes, Currency Exchange Rates instability accompanied with huge inflation rates in the recent past. Consequently, the fact that property records can be questionable represents the main shortcoming of the application of both historic costs methods (HC and IHC) in some CPs.

If RAB is revalued, realization of revaluation surplus should be considered when setting the amount of return on capital.

***Regulator should be entitled to request revaluation of fixed assets if deems it necessary. In addition, regulator should also be allowed to approve revaluation of fixed assets, particularly if significant difference arises between the book value and the revaluated value of the RAB.***

#### *3.1.1.3 Construction work in progress*

Construction work in progress (CWiP) describes the money that has been spent on an asset under construction that had not been commissioned yet.

[11] CEER, Report on Investment Conditions in European Countries, p. 118, 122
[12] CEER, Report on Investment Conditions in European Countries, p. 130
[13] The Swedish Energy Markets Inspectorate, Improved and clearer regulation of the electricity grid operators' revenue frameworks, p.31

During any price review, a number of distribution network facilities is in acquisition and under construction and regulator should decide how to reflect this issue concerning their RAB inclusion.

Regulators may decide to capitalize and include construction work in progress in the RAB, thereby providing early recognition of costs. This inclusion may be conditional depending on the time when construction is scheduled to be completed, e.g. before the end of the year for which the RAB is being calculated. Regardless of the recognition of investment costs, it should not be interpreted as a tacit approval of the assets value after commissioning.

Whenever the regulator chooses to include the investment as work in progress in the RAB, the current users of the service pay for the facility that is going to be used by future users, thereby violating the ''used and useful'' concept and the principle of cost reflectivity. This solution provides a cash flow for the project, but the investor is not incentivized to finalize the project as soon as possible.

Second option is that the regulator decides to allow capitalization of the borrowing costs (to add “bridging” finance costs to the future value of the asset). In this case costs of money to finance the project are added to the RAB once the project is completed and useful. The main disadvantage of this method is delay in payback giving rise to the price when the new facilities and the accumulated financing costs enter the RAB in one year. This situation is more likely to happen in transmission network regulation in comparison to the distribution networks, because of the higher relative value of individual investments in comparison to the RAB value. Since the investment is not capitalized nor paid back before it becomes operational, the investor has an incentive to finish the project as soon as possible while the ''used and useful'' concept is not violated.

Third option is to roll forward expenditures already incurred with an accumulated rate of return equal to that for operational assets to reflect final cost. The accumulated amount would be the amount added to the RAB when the assets become operational.

Costs of construction work in progress are recognized by regulators in 10 out of 23 European countries[14].

***Construction work in progress cost recovery need to be addressed with due consideration given to the other complementary aspects of network investment regulation, but also respecting the conflicting objectives such as ''used and useful'' concept and the principle of cost reflectivity.***

#### *3.1.1.4 Working Capital*

Working capital is important aspect of the electricity distribution regulation as it can affect the cash flow of the company.

The regulator might decide to consider an allowance for working capital, necessary for conducting a regulated business.

By definition, working capital is the average amount of capital necessary to finance business operations. Working capital includes inventories of material and spare parts at stock, petty cash, prepayments, minimum bank balances. Cash working capital is the average amount required to bridge the gap between the time from the payment for due payables until corresponding receivables are collected. If

[14] CEER, Report on Investment Conditions in European Countries, p. 106

consumers pre-pay for services, then prepayment is to be shown as an offset to cash working capital. There are two basic methods to determine the amount of required working capital, either as a difference between current assets and short term liabilities or using a lead –lag analysis. The first is based on the DSOs books of accounts, the latter is preferred, as it includes assessments of actual needs.

Different methods may be applied to calculate the appropriate level of working capital allowance, as the cash cycle method or several simplified methods.

Cash cycle method is also called lead-lag approach. It takes into account the average revenue lag, average expense lag and total expenses per day. This method is based on the amount of lapsed time from the payments (both the operating and the capital expenditures) until corresponding receipts (network tariff's revenue).

Several simplified methods for calculation are observed, where the working capital allowance is usually linked to the DSO annual revenue or the value of fixed assets.

For example, regulators in Romania and Bulgaria set working capital allowance equal to 1/8 of the revenue requirements based on the RAB without working capital. In Finland and Estonia, the amount corresponding to 5% of DSO net sales is provided as the necessary financial assets to safeguard network operations. In Norway and Denmark, the working capital allowance is set at 1% and 2% respectively of the total book value of fixed assets[15].

Different approaches are taken by regulators as discussed before and there is no common regulatory methodology to address working capital issue. According to the Council of European Energy Regulators (CEER) survey, 9 out of 23 European countries include working capital as a part of RAB[16].

In only 4 out of 9 EnC CPs[17] (Montenegro, Bosnia and Herzegovina, Albania and Moldova) working capital is added in the RAB. Regulatory authority in Montenegro sets the working capital allowance to 1/8 of the justified operational costs for distribution (including cost of losses), in Albania, it is set at 1/12 of the operational costs, while in Bosnia and Herzegovina (Republic of Srpska) working capital is calculated analytically based on the lead – lag analysis for necessary material and inventories (60 days funding), amount of revenues (15 days funding) and minimum daily cash.

The working capital inclusion in the RAB is a consequence of the time value of money. As long as there is a time lag between the moments at which a particular cost is incurred and its recovery via distribution tariff revenues, the capital is required in the meantime and there is a cost associated with that requirement. In some cases, this number can also be negative. Cost recovery in the region is generally provided with significant delay with the overdue payments in some of the EnC CPs exceeding 50 days[18].

***Similar arguments may be provided for the working capital to be treated in the same way as fixed assets, regarding the allowed rate of return. In both cases, investors commit funds either permanently***

[15] CEER, Report on Investment Conditions in European Countries, p. 103
[16] CEER, Report on Investment Conditions in European Countries, p. 104
[17] ECRB, Status Review of Main Criteria for Allowed Revenue Determination for transmission, distribution and regulated supply of electricity and gas, p. 16
[18] EIHP, Southeast Europe Distribution System Operator Benchmarking Study, p. 224

***or at a certain point in time and require a return on those funds to compensate for the opportunity cost. In that sense, there is no difference between financing the working capital and fixed assets.***

***Market opening and DSOs unbundling bring significant changes related to the revenue collection, since DSO may charge its services to the supplier or alternatively may continue to charge consumers directly, depending on the specific rules in force. The paradigm change is likely to change average revenue lag, consequently regulatory framework should be timely adjusted to the new conditions regarding the working capital allowance.***

#### *3.1.1.5 Asset's exclusion*

It is a general rule that regulator is authorized to exclude some assets from the RAB, in case that an asset belongs to one of the following categories:

- Assets not intended for the distribution functions,
- Assets that did not pass the prudency test,
- Capital contributions - grants or subsidies from e.g. the municipal, province or state government or an international institution,
- Participation of third parties in the construction of distribution system,
- Connection assets financed by the network users.

In Georgia, Serbia and FYR of Macedonia, it is envisaged that an asset can be excluded from the RAB because the investment is declared to be imprudent. In that sense, regulators may use different criteria to assess whether the investment should be included in the RAB. This test may be applied either on ex-ante basis to assess the likelihood of investment inclusion in the RAB, or on ex-post basis to provide final regulatory approval of capital expenditures.

Capital contributions from different authorities may include cash injections for network investment purposes, gifting of assets, selling of assets below cost etc.

Exclusion of different forms of capital contributions is needed to avoid return on assets that are not financed by the regulated company. In all EnC CPs capital contributions are excluded from the RAB.

Capital contributions concept is widely used by regulators, thereby regulators are expected to establish clear rules regarding the contribution's classification, accounting and disclosure for regulatory purpose. Regulatory framework should provide precise definitions of capital contributions, as well as the responsibilities of regulated utilities to keep separate accounting records of the assets financed by capital contributions including their net value, depreciation and disposal value.

Participation of third parties may include network facilities constructed beyond individual connection assets to serve their primary needs, which are then handed over to the DSO to operate and maintain.

Exclusion of connection facilities financed partially or in full amount by third party from the RAB is a common practice in EnC CPs. Question whether the exclusion from the RAB is justified or not is a matter of consistency and should be considered in a wider context of distribution services regulation. In principle, costs and revenues associated with assets excluded from RAB should be taken into account in a consistent manner.

Network connection and network use are standard DSO services provided under regulated terms and conditions. From that perspective there is no difference whether the distribution facility is financed through network connection fee (ex-ante) or use-of-network tariffs (ex-post), as in both cases end users pay regulated charge for DSO's standard service. In addition, it is worth to emphasize that revenue from connection fees have a direct interdependence with the use-of-network tariffs level, as the higher share of connection costs paid by end users lowers use-of-network tariffs level and vice versa.

It is a general rule that end user is not in charge of the connection facility maintenance once the facility is commissioned as a DSO's asset. Furthermore, connection assets replacement at the end of life time or as a result of wear and tear is a pure DSO's responsibility. In addition, during the connection asset's life time DSO may incur costs of assets reconstruction as a result of urban planning requirements or costs of metering infrastructure modernization. Therefore DSO's total allowed revenue should also include capital and operating costs related to the connection facilities, taking into account that DSO is in charge of repair, maintenance and renewal of all network assets including connection facilities too.

***The end users contributions in the connection assets represent the upfront payment for the DSO services, whereby connection assets are integral part of distribution network. Having regard to all the foregoing considerations, it is recommended that end users contributions should be incorporated in the regulatory framework through the revenue adjustments, rather than through assets exclusion from the RAB. Connection fee paid by end user either through cash contribution or through connection assets construction should be recognized and treated in the same manner.***

#### *3.1.1.6 Assets in use of zero carrying value*

It often happens that useful technical life of some assets is longer than depreciation period, causing the situation when asset is still in use although its estimated useful lifetime had expired. This situation might also happen if too short depreciation periods are generally applied, thereby bringing a risk of fully functional assets being replaced at the end of economic life, solely because they do not generate return on capital, although the operation and maintenance (O&M) costs are lower than the capital costs of new investments.

In this case the accumulated depreciation is equal to the initial asset value and the asset has zero book value. Regulatory framework should reasonably address the issue when asset is fully depreciated, but is still useful. If rate of return is fairly determined, the company is incentivized to replace the depreciated asset as soon as possible.

Prolonged use of depreciated assets usually has positive socio-economic effect, provided that relevant running operation and maintenance costs are lower than capital costs of new facility. In order to avoid loss of social benefit of prolonged use of depreciated assets, some form of incentives for the DSOs might be provided as a sharing of socio-economic benefits of prolonged life time. It should reflect fair balance between required increased maintenance costs of those assets and capital costs of new assets. Without such incentive, all benefits would be allocated on the consumer's side, so that DSO has no interest to prolong asset's utilization. However, regulatory framework should not incentivize use of assets at any cost, due to the possible deterioration of quality of supply and the increase of O&M costs over time.

***In that sense, reasonable trade off should be considered between costs of maintenance of depreciated asset and capital costs for new asset in order to maximize overall social welfare.***

#### *3.1.1.7 RAB specific considerations at privatization*

The RAB valuation is of particular concern in case that regulated utility's assets are privatized with the privatization discount. Allocation of the privatization discount, RAB value, fair rate of return and the depreciation method are the issues that require consistent regulatory solution.

For those purposes, UK experience from a period of privatization in the 1980s is valuable, since the assets were sold at a substantial discount. In this case negative goodwill had arisen as a difference between the book value and the purchase price.

First open issue was the allocation of the privatization discount in situation when the network and non-network businesses were privatized together. The problem in UK was resolved by the Monopolies and Merger Commission, which decided in favour of the spread of the privatization discount between the transport business (regulated activity) and the storage business (market activity), although there were initiatives to allocate the full value to the regulated activity.

To address the second open issue related to the RAB valuation, market to asset ratio (MAR) was introduced, and it was generally accepted that value of RAB should be written down initially from its book value by the MAR factor. The value of the RAB will retain its privatization discount relative to net book value as long as the pre-privatization assets remain in use. General conclusion derived is that if there were no allowance for the MAR, shareholders would enjoy significant and excessive gains at the expense of their customers.

Application of the MAR factor kept consistency with depreciating the assets paid for by the investors, as the true current cost of the assets to the shareholders was the discounted value reflected in the share price. There was an alternative option to keep full depreciation on the original assets but only while the regulatory value of these original assets is positive, but it would worsen the problem of inefficient time profiles of prices.

British Gas post privatization experience regarding the rate of return calculation is provided here to illustrate the UK practice in this specific situation. Return on their investment was calculated in two parts: a discounted rate of return on "existing assets", reflecting the fact that the market value of British Gas shares was 60% of their book value at the end of 1991[19]; while "new" assets should receive the full cost of capital on their net book value.

If the RAB is determined at the scaled down value of privatized assets and the real value of new investments and if the depreciation is correctly calculated, there is no need to use different rates of return for new and old capital.

### 3.1.2 Rate of return

The rate of return is important input in the price regulation, having in mind that electricity distribution is a capital intensive activity with the high share of capital costs.

The rate of return is expected to satisfy minimum requirements given by investors in order to commit capital to a particular company or project. A fair rate of return is to be decided by regulator, assessing

[19] David M Newbery, Determining the regulatory asset base for utility price regulation, Utility Policy, Vol 6, No.1, pp. 1-8

the return that investors in these firms would have earned if they had invested in any firm with a comparable level of risk. In situation when the allowed rate of return exceeds the cost of capital, it may happen that shareholder overinvest in the unnecessary regulated assets (investment gold plating), thus making an extra profit on the capital costs difference; situation which is also known as the Averch–Johnson effect. This effect is generated when rate of return regulation encourages a firm to invest more than the cost effectiveness criteria would require.

For calculation of the return on the regulatory asset base, a common approach in European countries is the WACC method, calculated as a weighted cost of debt and equity with regard to the DSO's capital structure. There are only a few exceptions in Europe regarding the rate of return setting, when other than WACC methods are applied to set reasonable profit rate (Germany, Denmark, Spain and France[20]).

In order to make data from different countries comparable, it is necessary to make distinction between the real and nominal rate of return. A real rate of return is the annual percentage of return realized on an investment, which is adjusted for changes in prices due to inflation or other external effects. A nominal rate of return is the amount of money generated by an investment before counting expenses such as taxes and inflation. Attributes pre-tax and post-tax denote whether the rate of return includes or not a tax rate allowance. If post-tax WACC is applied, projected tax payments are included as a part of utility's allowed costs. Vanilla WACC is a combination of two methods, which uses a pre-tax cost of debt and a post-tax cost of equity.

Currently none of the European countries applies post-tax WACC[21], while three countries apply Vanilla WACC (Belgium, Great Britain and Latvia).

General WACC equation for nominal pre-tax rate of return is:

$$WACC_{pre\text{-}tax} = D * (Rf + DP) + E * (Rf + e\beta * RP) / (1\text{-}T)$$

WACC calculation parameters are:

- D – Debt share of capital structure,
- E - Equity share of capital structure,
- Rf - Risk free rate (nominal value),
- DP – Debt premium,
- eβ - Equity beta,
- RP - Market risk premium,
- T - Tax level.

Tax rate adjustment with the factor (1-T) is commonly not applied at the debt part of WACC equation, because of the assumption that interest payments on debt are tax deductible at the corporate level.

Above stated WACC equation may also include country risk premium at the equity side, provided that specific country risk is not incorporated in other risk rates used in WACC calculation. Country risk premium might be used to reflect the risk of adverse political, regulatory and economical conditions in the country that are not otherwise factored in.

[20] CEER, Report on Investment Conditions in European Countries, p. 24
[21] CEER, Report on Investment Conditions in European Countries, p. 24

Without reasonable rate of return in correlation with consistently applied depreciation policy, it is hard to expect that investor's confidence shall be ensured, due to low predictability and certainty that invested capital shall be recovered and that DSO shall have sufficient funds at its disposal to finance network investments. The low rate of return directly impacts 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.

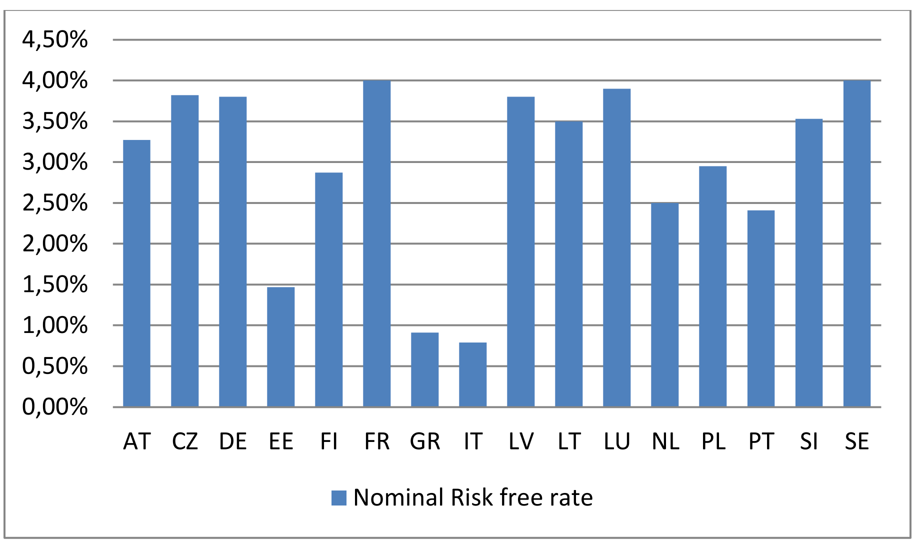
***Rate of return impact on the retail electricity prices is not the only aspect of price regulation to be considered, as its level has much broader relevance. Reasonable rate of return is also seen as a key precondition for quality of supply regulation, as discussed in chapter 4 of this Report.***

***Setting a low rate of return as the vulnerable consumers' protection tool, to keep low level of retail electricity prices, should be avoided, since the understated electricity prices can not resolve poverty issue, but may endanger medium and long term sustainability of power sector due to distorted price signals. Furthermore, trade–offs between the return on assets and other disapproved costs of regulated companies should be avoided, as it affects transparency of tariff setting process.***

#### *3.1.2.1 WACC parameters in EU*

In countries with stable regulatory framework it is generally accepted that government bonds long term yield is to be used as a value of risk free rate. It is assumed that this rate reflects only the time value of money as the expected returns are certain. The risk free rate can be given as either nominal or real; with the difference that real risk free rate excludes inflation and reflects the pure time value of money.

Values of nominal risk free rates in some European countries are provided in Figure 2[22], where the average value at the sample level is 2,97%.




*Source: CEER*

**Figure 2** *Nominal Risk free rates in some European countries*

[22] CEER Report on Investment Conditions in European Countries, p. 39

Equity beta (levered beta) is another important parameter of WACC calculation, as it is a measure of relative degree of investment risk associated with specific assets and industry. Its valuation is one of the most challenging issues for regulators as a very small change in estimation has significant implications on the revenue requirements. Equity beta calculation is based on asset beta (unlevered beta), debt to equity ratio and tax rate, as it is given by following equation:

$$\beta_{Lev} = \beta_{UNLEV} \times \left[1 + (1 - T) \times \frac{D}{E}\right]$$

Asset beta is generally low in countries with stable and predictable regulatory framework. The values of asset beta are in the range 0,3-0,4 in continental Europe[23], while similar values are observed in Nordic countries[24]. This parameter is usually indirectly set by Regulator, as it is common practice that regulators set equity beta parameter. In some cases regulators are not taking into account taxes and the equation becomes even simpler:

$$\beta_{Lev} = \beta_{UNLEV} \times \left[1 + \frac{D}{E}\right]$$

Prevailing regulatory practice in Europe takes into account taxes too.

Equity beta is calculated as the covariance of the utility's share price with the average price of shares at the stock market. Unity value of this parameter means that the risk associated with the regulated activity is equal to the average risk at the broader market. When electricity distribution companies are considered, it is reasonable to expect that equity beta value is well below unity value as the company's revenues vary hardly at all with the general state of the economy.

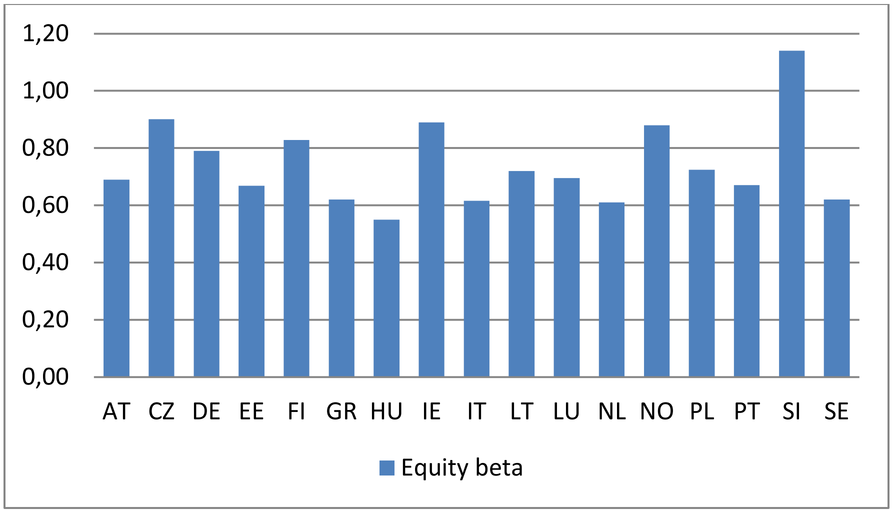
If utility's share prices are available for a short period or if the share prices are not listed at the stock market, equity beta may be estimated on the basis of international comparison. Insufficient data entail risk of arbitrarily set values in the equation with significant impact on the approved return and revenues.

The values of equity beta for some European countries are given in Figure 3[25].

[23] E&Y, Mapping power and utilities regulation in Europe, p. 13

[24] NordReg, Economic regulation of electricity grids in Nordic countries, p. 34

[25] CEER Report on Investment Conditions in European Countries, p. 80



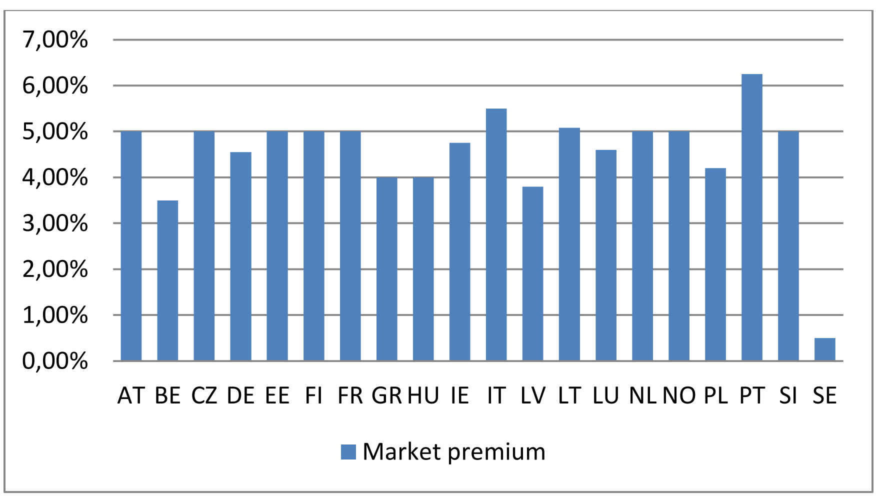

*Source: CEER*

**Figure 3** *Values of equity beta in some European countries*

Average value of equity beta at the sample level is 0,74, while the majority of regulators set this parameter in the range 0,6-0,8. Slovenia is the only EU country where equity beta is higher than unity value.

Market risk premium is the amount of return that investors are allowed because of the uncertainty of actual profits. This parameter is a result of the market valuation of equity risk.

Values of market premiums in European countries are provided in Figure 4[26], where the average value at the sample level is 4,54%, with the very strong convergence of values across the Europe in the range 4%-5%.



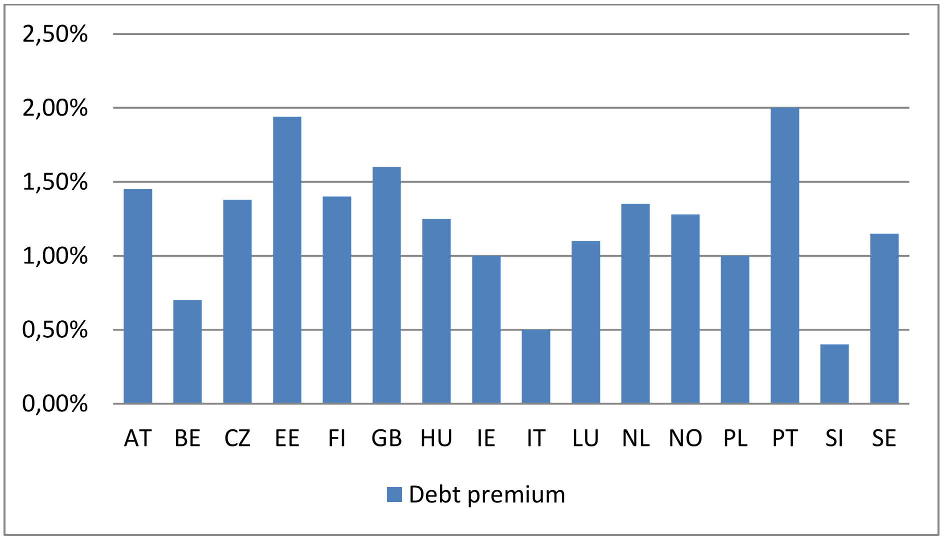

*Source: CEER*

**Figure 4** *Market premium rates in European countries (in 2016)*

[26] CEER Report on Investment Conditions in European Countries, p. 57-58

The debt premium in addition to the risk-free rate is assumed to estimate company's specific overall cost of debt. Overall cost of debt may also be obtained from the utility's quoted existing debt.

Values of debt premium in some European countries are provided in Figure 5[27], where the average value at the sample level is 1,22%.




*Source: CEER*

**Figure 5** *Debt premium rates in some European countries*

Important parameter in WACC calculation is a gearing (also called financial leverage) that reflects the percentage of capital available for an enterprise that is financed by debt and long-term arrangements. Regulator may decide to use actual gearing ratio or otherwise to set assumed optimal capital structure with expectation that regulated utilities should stick to the regulated value.

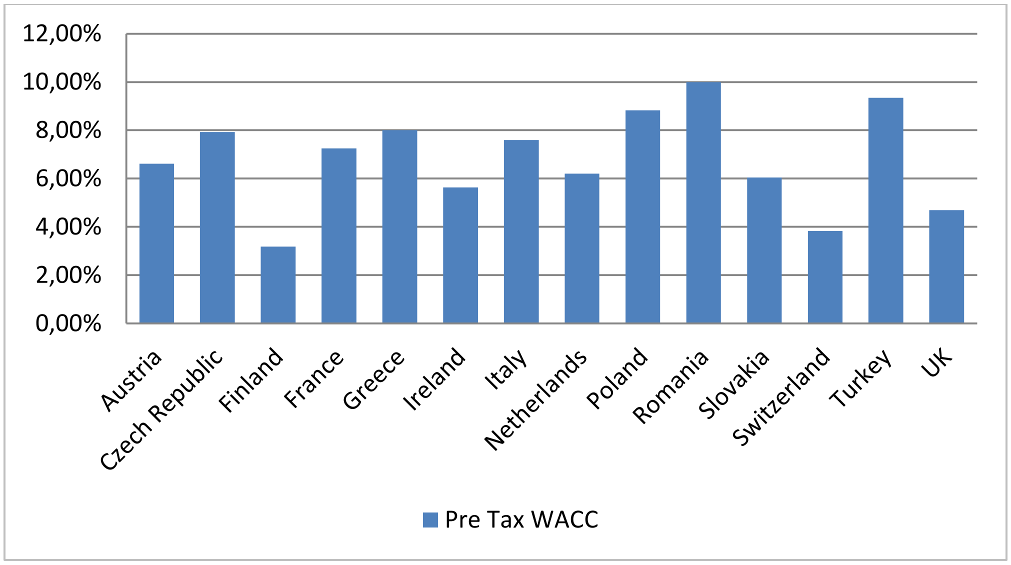
Average values of gearing in EU Member States are in the range 40-60%[28], with the increasing trend towards the higher level of debt. The lowest value of gearing is observed in Greece (39%), while a number of regulators apply preset gearing value of 60% for WACC calculation. Debt based capital structure is a source of concern for regulators, whether the projected revenues, profits and cash flows are sufficient to enable normal operations and funding of new investments. Concerns are particularly raised if a company becomes financially distressed as a result of over excessive debt structure. Insolvency of regulated companies which provide public services may have systematic negative effects that go far beyond the entity and its shareholders. Regulators are expected to intervene if they estimate that excessive use of debt may cause negative consequences for the whole society.

Theoretically, changes in the capital structure should have no impact on the overall WACC, in particular when measured on a post-tax basis. As gearing increases, the equity beta should increase linearly (provided the underlying asset beta is constant) thereby offsetting any benefit from the greater use of

[27] CEER Report on Investment Conditions in European Countries, p. 45
[28] CEER Report on Investment Conditions in European Countries, p. 66

cheaper debt. But there has clearly been a perception amongst regulated companies that the increasing financing from loans can lower the cost of capital, and as a result there has been a significant increase in gearing across the utility sector. Setting a post-tax cost of capital is seen as a potential tool to reduce incentives to increase gearing for purely tax-driven reasons, particularly if any benefits from increasing gearing above assumed levels are clawed back at subsequent reviews. In that sense, regulator may decide to claw back any tax-driven benefits from increasing gearing above assumed levels during the tariffs review procedure. Alternative tool that may be applied by regulator to counteract the gearing increase is to set higher level of cost of equity.

Pre Tax WACC values in some of the European countries are given in Figure 6[29][30].




Source: Ernst&Young (survey 2013), IERN (survey 2010)

**Figure 6** *Pre Tax WACC in some European countries*

The WACC values provided for Finland, Ireland and UK are real rates of return, with the difference that WACC value for Finland is post-tax.

Specific solution is applied in Germany where regulatory regime does not use the WACC concept and allows different return on the new and the old equities, 9,05% nominal and 7,14% real respectively[31]. Return on debt is treated separately.

Another specific solution is provided in Denmark, where WACC model is not applied to determine the allowed rate of return on capital. A DSO's annual profit from operating its distribution grid is not allowed to exceed the interest rate on the 30-years maturity bonds plus 1 %. In 2013, the allowed rate of return was 4,478%[32] (nominal pre-tax).

[29] IERN, Overview of European Regulatory Framework in Energy Transport, p. 23
[30] E&Y, Mapping power and utilities regulation in Europe
[31] CEER Report on Investment Conditions in European Countries, p. 23
[32] EURELECTRIC, Electricity Distribution Investments: What Regulatory Framework Do We Need, p. 12

In Norway, all parameters in the WACC formula except for the risk-free rate are fixed, and the WACC equation is converted to the simple one for pre-tax calculation of the nominal rate of return[33]:

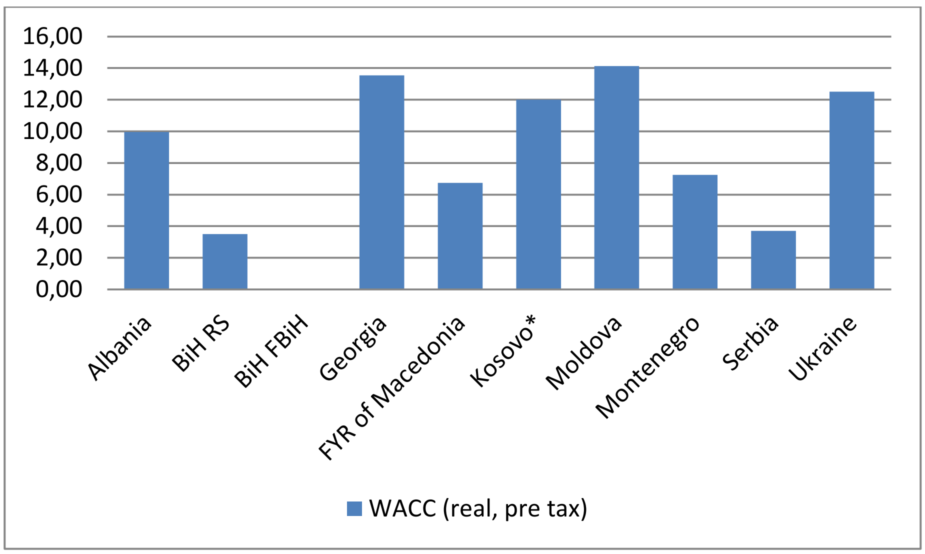
$$WACC = 1{,}14\,Rf + 2{,}39\%$$

Another specificity of Norway is guaranteed lower threshold of actual profit, set at 2% over the last five years. Any company that falls below this minimum return will get a correction to maintain at least a 2 % return on capital.

Data provided from a number of European countries show a strong correlation that can be explained not only by stable and predictable regulatory framework, but also with the stability of capital market, without significant deviations among them.

### *3.1.2.2 WACC parameters in EnC CPs*

Contrary to the situation in EU, where the allowed rates of return are within the narrow range, the data provided by the ECRB Status Review[34] show a large divergence of the allowed WACC in EnC CPs.




Source: ECRB (survey 2013)

**Figure 7** *Pre Tax WACC in EnC CPs (%)*

The WACC for Georgia is the calculated value based on the WACC parameters defined for the transitional period in 2014[35].

Regulators in Bosnia and Herzegovina and Serbia allowed very low rate of return when compared to the expected market values. In Federation Bosnia and Herzegovina (Bosnia and Herzegovina) rate of return is not recognized at all. Approved levels in Serbia and Bosnia and Herzegovina (Republic of Srpska) are in the range of government bond rates that are commonly used as the reference risk free rates, meaning

[33] NordReg, Economic regulation of electricity grids in Nordic countries, p. 94

[34] ECRB Status Review of Main Criteria for Allowed Revenue Determination for transmission, distribution and regulated supply of electricity and gas, p. 18-19

[35] GNERC, Tariff Setting Methodology for Electricity Distribution, Pass Through and Consumption Tariffs, Article 25

that no risk premium is factored in. In all those cases DSOs are state owned and regulators presumably used low rate of returns in order to avoid significant price increase to household consumers and industry.

Regulators in Albania and Montenegro seemed to provide the rate of return that reflects the market prevailing conditions in those countries, but the conclusion may be misleading regarding the profit achievability, as the regulators did not recognize the full costs of distribution losses. In both cases, the level of approved losses (19,92% in Albania and 9% in Montenegro) is much lower than the actual values in 2016 (28% in Albania and 14,7% in Montenegro). In Montenegro, approved level of losses has been decreased to the level of technical losses following the decision of the Constitutional Court from 2011[36].

Similar situation was observed in the FYR of Macedonia too, with the difference that DSO in 2016 managed to approach the approved level of losses. For these CPs it is therefore reasonable to conclude that regulators opted to allow the higher rates of return, but to keep stricter criteria for costs approving, such as those linked to the non-technical losses.

There is a lot of variation among the EnC CPs with regard to the ''Risk free rate parameter'', which ranges from 1,93% in Montenegro, up to 7,43% in Albania. Strong variation is not a consequence of the extremely different conditions at the financial markets of those countries, but it results from the application of USA government bonds risk-free rates in Moldova and German government bonds rates in Montenegro. It is worth noting that it is not unusual for regulators to apply international practice to set WACC calculation parameters if country's data are not applicable for some reason.

Similarly, equity beta coefficient also varies from 0,47 and 0,68 in Moldova and Montenegro respectively up to the 1,32 in Albania. Relatively low values in Moldova and Montenegro are result of international benchmarking. If values for these countries are excluded from analyses, the lowest equity beta coefficient is 1 in FYR of Macedonia and Kosovo*.

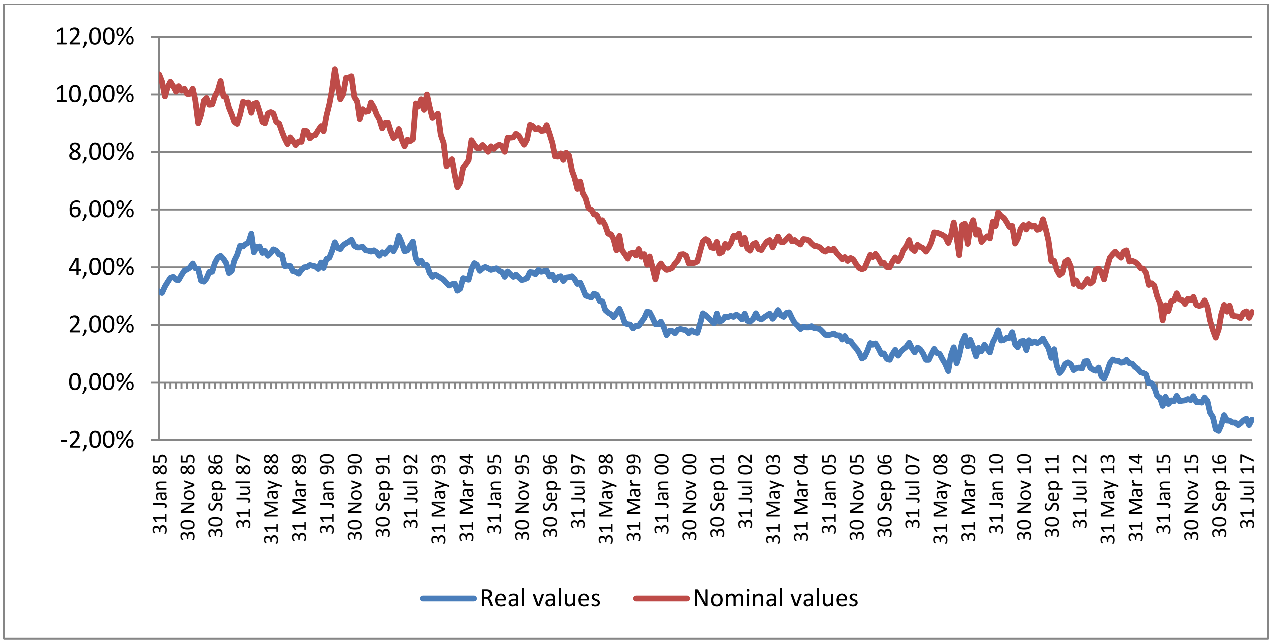
#### *3.1.2.3 WACC trends*

Recent price determination in Europe is characterized by downward trend of returns, as a consequence of numerous factors. Regulators are less ''generous'' than before, risk premium associated with regulated activities are being lowered and the gearing is increased.

Data on the government bonds long term yields show downward trends in the majority of countries, thereby directly influencing the level of risk free rate used in the WACC calculation.

Figure 8 shows the nominal and the real (inflation adjusted) forward looking yields on government bonds (10 years maturity) in United Kingdom for the period 1985-2017. Starting from 2014 real forward looking yields on government bonds have recorded negative values.

[36] For more information please see Country Case Study 2 - Montenegro




Source: Bank of England

**Figure 8** *Government bond yields in United Kingdom (1985-2017)*

As an example, the Dutch regulator made significant decrease of the regulated rate of return in 2013, by approving 3,6% for the next regulatory period instead of previous 6,2%[37]. In Finland approved rate of return for 2014 is decreased from 3,19% to 3,03% real post-tax[38]. Similar trend is observed in the USA[39], where the historical low level of returns is recorded in 2012, reflecting the declining interest rates.

***If the recent trends with low yields on a government bonds would continue, WACC calculation methodology may entail amendments to reflect capital costs of a network company.***

#### *3.1.2.4 DSO credit rating and RoR*

All the main credit ratings agencies operate in the infrastructure area and pay considerable attention to RAB regimes and their security.

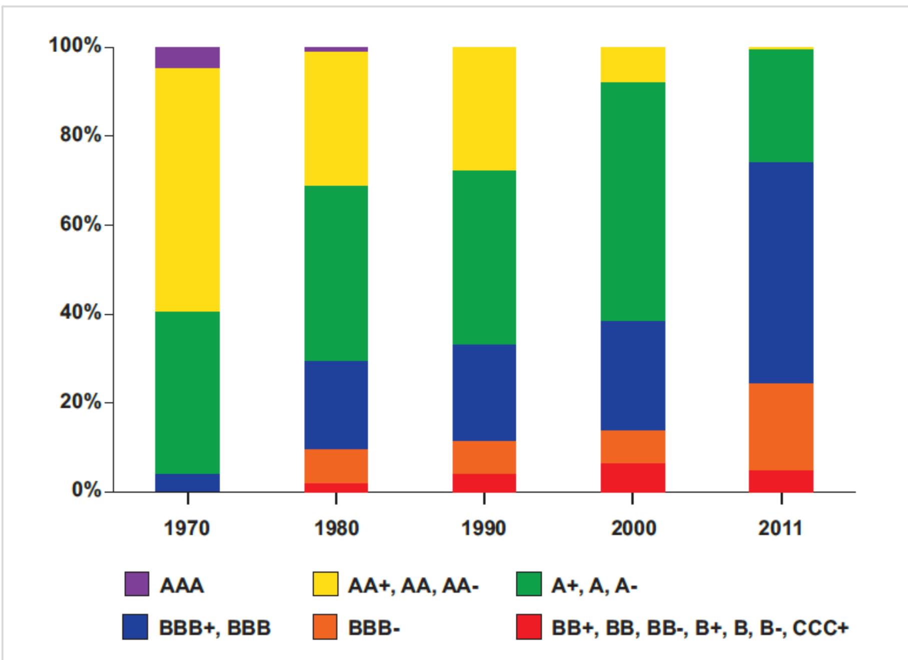
Moody's ''Rating Methodology Regulated Electric and Gas Networks''[40], sets out four key factors that constitute the rating agency's analytical framework. The overall country regulatory environment and asset ownership model is one of the key factors, having a specific weight 40% of the overall score. Within this factor, Moody's currently assign a score for ''Stability and Predictability of the Regulatory Regime'' at 15% plus additional 15% for ''Cost and Investment Recovery''.

[37] EURELECTRIC, Electricity Distribution Investments: What Regulatory Framework Do We Need, p. 15
[38] EURELECTRIC, Electricity Distribution Investments: What Regulatory Framework Do We Need, p. 16
[39] Edison Electric Institute, Disruptive Challenges, Response to a Changing Retail Electricity Business, p. 14
[40] Moody's ''Rating Methodology Regulated Electric and Gas Networks'', latest edition March 2017

During the 2013 Moody's had assigned the regulatory regime in the UK a highest score of Aaa[41] for the regulatory stability and predictability sub-factor, whereupon Moody's uses the UK regulatory regime as a benchmark for Europe in terms of stability and predictability of the relevant framework.

As an example, during the 2010 Moody's downgraded to Baa1 the general ratings of three electricity distribution utilities in UK to reflect the impact of the additional leverage at the three DSOs following their acquisition by UKPNH, and that their ratings no longer incorporate an element of support from membership of the EDF Group. In its rating rationale Moody's emphasized that: *''The Baa1 ratings primarily reflect the very low business risk profile of the companies as monopoly providers of electricity distribution services in their licensed areas. The utilities' business is conducted within a regulatory framework that Moody's regards as well-established and generally transparent, thus providing a good degree of stability and predictability of cash flows''*.

In the USA steady decline of the power utilities credit rating is observed in the last decades as a result of numerous factors. Figure 9 provides a credit rating history (Standard & Poor's) of the electric utility sector in the USA for the period 1970-2011[42].




*Source: Edison Electric Institute*

**Figure 9** *Electric utility industry credit ratings distribution evolution in USA*

Rating agency reports which provide rating for specific infrastructure business are directly influencing the capital market. In that sense, stability and predictability of the RAB based regulatory framework had proved to be the key factor that lowered the credit costs for investments in regulated infrastructure. Distribution utilities have experienced access to relatively low-cost capital, thanks to the relatively stable

[41] City University London, The role of the regulatory asset base as an instrument of regulatory commitment, p. 18
[42] Edison Electric Institute, Disruptive Challenges, Response to a Changing Retail Electricity Business, p. 10

credit ratings and confidence that investors place in the regulatory model, thereby contributing to the lower tariff rates for electricity consumers.

***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.***

***In situation when company has bankability problems as a result of excessive indebtedness, regulator may require company to maintain an investment credit rating provided by the independent rating agency.***

#### *3.1.2.5 Country Case Study – Sweden*

Swedish Regulator (Ei) set 177 DSO's revenue caps for the regulatory period 2012-2015, which were based on rate of return of 5,2%. Out of 177 decisions, 96 were appealed to the Administrative Court. The appeals mainly related to what came to be called the transition method and to the return rate. The transition method was part of Ei's procedure and entailed making the revenue caps reasonable by limiting these on the basis of the companies' historical charges. A transition rule was enforced for the new ex-ante model, meaning that 1/3 of the companies' allowed income will be based on the current model and 2/3 will be based on historical income (2006-2009). According to EURELECTRIC analyses[43], this in addition reduced the achievable regulated rate of return from 5.2% to 3.2%.

This method was rejected by the Administrative Court and the Administrative Court of Appeal. The Court decided that regulator did not have a right to apply transition period and also changed allowed rate of return to 6.5 per cent[44].

Regulator considered the level of the return rate for 2012–2015 to be unjustifiably high for operations with unusually low risk and appealed to the Supreme Administrative Court. However, Regulator was not granted leave to appeal.

The companies that have not appealed regulator's decisions had the opportunity to request a change of their revenue caps based on the judgments of the Administrative Court of Appeal.

Ahead of the 2016–2019 regulatory period, regulator made 185 decisions on DSO's revenue caps with the level of the return rate set at the 4,53%. Approved rate of return was based on the three reports prepared by consulting firms, Ernst & Young (4,42%), Montell & Partners (4,55%) and Grant Thornton (3,8%)[45]. Out of 185 utilities, 81 DSOs representing more than 75% of total market, have appealed to the Administrative Court requesting rate of return of 6,3%.

On 14 December 2016, the Administrative Court ruled that the WACC for the period 2016-2019 should be 5,85%, based on the expert opinions and investigations[46]. In late December 2016, Regulator had appealed to the Administrative court of Appeal, but it has to be granted leave to appeal.

[43] EURELECTRIC, Electricity Distribution Investments: What Regulatory Framework Do We Need, p. 15
[44] The Swedish Energy Markets Inspectorate's, ANNUAL REPORT 2015, p. 15
[45] Ellevio, Supplementary Prospectus dated 30 December 2016
[46] The Swedish Energy Markets Inspectorate's, ANNUAL REPORT 2016, p. 25

### 3.1.3 Depreciation

Depreciation is as 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. Depreciation is also viewed as a capital recovery, that is the spreading of the asset investment over time to be recovered in revenue requirement. Depreciation method defines how the capital costs are allocated and recovered over 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 distribution sector that provides stable cash flow for the DSO and gives more price predictability for end consumers.

Alternative to straight-line depreciation is the accelerated depreciation which is front loaded, i.e. it is higher in early years, such as the sum of the years' digits depreciation or reducing balance depreciation (diminishing value) methodology as used for taxation purposes in many countries. Use of accelerated depreciation method with decreasing allocations might be justified where assets can be expected to yield more service in earlier years or when regulator decides to adjust depreciation period to ensure that the periods of cost recovery and debt repayment are aligned to the reasonable extent.

Beside the straight-line and the accelerated depreciation methods, functional depreciation method may be applied, based on the number of units of outputs created from the usage of an asset. This 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.

Straight-line method of depreciation is applied in all EnC CPs. Specific solution is provided by regulator in Kosovo* where depreciation costs are included only for assets acquired after 2006, based on the assumptions that older assets are fully depreciated and have zero value.

The asset life for regulatory depreciation may differ from the asset life for financial accounting purposes. The general aim from a regulatory perspective is to align the depreciation period as close as possible with the asset’s technical life. Asset’s stranding is a situation when asset still has certain value in the balance sheet, but is either obsolete or not used /underused as compared with initial expectations. In this situation DSOs are required to replace or to write off and decommission the network assets even though they have not recovered full costs of disposed assets. Associated costs of stranded assets should be recognized in case that depreciation period, set by regulatory authority, is not determined in accordance with the relevant technical data.

Majority of regulators in EnC CPs decided to apply asset lives as defined by the regulated companies, in line with applicable national accounting standards and rules, with the exception of Serbia, Georgia and Kosovo* where the asset lives are defined by regulator[47].

For regulatory depreciation purposes it is possible to apply individual life time for each specific asset type (cable, overhead line, transformer, electricity meter etc.) or alternatively average life time for

[47] ECRB Status Review of Main Criteria for Allowed Revenue Determination for transmission, distribution and regulated supply of electricity and gas

assets groups may be defined to make calculation simpler. However, individual DSO's network structure may not be properly reflected if the second approach is applied.

Regulator should also consider if there is a difference between the regulatory depreciation method and the depreciation method that is applied for tax purposes, as the additional taxable differences may occur. These items should be addressed and recognized as a part of DSOs' costs or revenues, as appropriate.

***Regulatory depreciation policy is considered to be one of the key preconditions for the stability and predictability of the regulatory framework, thereby providing certainty to investors that invested capital shall be recovered during the asset's life time.***

## 3.2 POSITIONS - CAPITAL COSTS

| | |
|---|---|
| FIXED ASSETS, RECOGNITION OF THE FAIR VALUE | If the assets records are reliable and there is no indication of impairment, the Historic Cost method is recommended to determine fair value of assets.<br>Replacement cost method is an optimal solution when missing evidence of fair value of assets is reported as a result of poor records, currency exchange rate volatility and inflation.<br>Regulator should have wide competences with regard to the initiation and approval of the revaluation of fixed assets. |
| 3.1.1<br>FIXED ASSETS, RECOGNITION OF ASSETS NECESSARY FOR OPERATION | Working capital is an integral part of the RAB. The recognition of required amount of working capital has to be flexible to reflect changes in the business environment and requirements imposed on DSO.<br>Recognition of Construction work in progress, either at the amount of carrying value of investment costs or the planned amount shall reflect the prioritization of the regulatory objectives. If recognized and included in RAB, it is advisable that the investment plans are submitted and reviewed by regulator.<br>When Intangible assets are recognized as a part of RAB, due consideration should be given to the specifics of goodwill and its treatment to be defined in advance.<br>Assets not intended for the distribution functions, capital contributions and assets financed by third parties are usually excluded from the RAB. In such a case, regulatory policy and methodology must be clear as regards the corresponding costs and revenues. As a matter of consistency, if costs are not recognized within the approved O&M costs, any corresponding revenues earned from usage of such assets must not be calculated as a deductive item.<br>Depending on the regulatory framework, the connection facilities procured or financed by network users might be included in the RAB, but the customers benefits are to be reflected through the revenue adjustments.<br>Assets which have reached end of their economic life time, but are still operative and used by DSO, should not be written off and excluded from the RAB. Some form of incentives for DSO not to scrap usable assets even if their carrying value is zero and earn no profit, should be provided in order to maximize overall welfare for both sides.<br>Respecting the paramount principles of predictability and consistency, annual adjustment of the RAB during the regulatory period should not be performed, unless the annual ratio of new investments value and depreciation significantly deviates from unity value. When necessary, differences may be reconciled during the several years of subsequent regulatory period. |
| 3.1.2<br>RATE OF RETURN | The rate of return at the reasonable level reflecting the prevailing conditions at the broader market in the EnC and CP, with gradual changes, if necessary, is assumed to bring more predictability and investor’s confidence. |

| | |
|---|---|
| | Reasonable rate of return in combination with consistently applied depreciation policy should provide strong regulatory commitment that invested capital shall be recovered and that DSO shall have at its disposal sufficient funds to finance network investments.<br><br>Having in mind generally low risk nature of the regulated electricity distribution activities, it is expected that equity beta used in WACC calculation should be set lower than unity in any case. |
| 3.1.3<br><br>DEPRECIATION | Straight line depreciation method is well proven as the simplest approach in the electricity distribution sector.<br><br>Regulatory depreciation periods should be aligned with the accounting practice and/or the technical life time of network assets to the extent possible.<br><br>Regulatory depreciation policy should be consistently applied throughout the life time of the network assets.<br><br>Specific asset's type individual life times and depreciation rates are preferred compared to the lump values at the network level.<br><br>Regulatory depreciation policy should strive to avoid either the risk of assets stranding due to too long expected regulatory lifetimes or the risk of overinvestments due to too short lifetime when fully functional assets are being replaced, solely because they do not generate returns. |

## 3.3 OPERATING COSTS

Operating costs are usually classified as controllable and non-controllable ones.

Non-controllable costs are the costs which the company has no or little possibility to influence. Those costs are typically treated by regulators as a cost-pass-through variable. Different taxes (income tax, franchise fee, property tax, excise tax etc.), TSO and market operator charges, regulatory costs and environmental regulations are examples of non-controllable costs. Regulated company should be protected from the risk of their occurrence and volatility with additional ex-post assessment and adjustment.

Controllable costs can be influenced by the company, thereby regulator may decide to incentive the company to decrease them over the time for a given level of efficiency.

The controllable O&M costs mainly comprise personnel (excluding labor costs used for network facilities construction) and material costs, procurement of network losses, customer services (metering, billing, collection), bad debts, insurance costs, short-term loan interest costs, corporate overhead costs, internally procured services and purchase of external services (outsourcing). These costs may also include costs of leasing in case that DSO leases assets for providing regulated services. As a general rule, regulators recognize only costs for an efficient running of a network.

The controllable O&M costs may be indexed for inflation by applying the consumer price index or some other indexation method.

Operating costs related to the assets excluded from the RAB, may be approved and included as a 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 lines financed through the grants or by investors).

Due attention should be given to the exceptional expenses that may incur occasionally as a result of extreme weather or natural disasters. Those costs have to be clearly distinct from the other O&M costs and, if allowed, normalized (spread over multiple years) and maintained and controlled under special scheme. Regulatory monitoring should be used to prevent misuse of these funds for other purposes.

Severe weather conditions such as storms and windstorms, floods, fires, heavy snow, extremely low and high temperatures are increasingly occurring with devastating effects on network infrastructure. Consequently DSOs have to cope with much higher operational expenses that are difficult to predict and quantify. Furthermore, DSOs may also face higher capital expenses due to the replacement of overhead lines by underground cables in order to avoid damages during the emergency conditions.

Regulator may decide to approve estimated annual budget for emergency handling, or otherwise regulator may preform ex-post analyses and approve actual costs incurred to manage and/or restore operation during and after such extreme weather and natural disaster related event. Alternative option is to obligate DSO to provide assets insurance policy with the regulatory recognition of insurance costs as a part of OPEX costs.

As an example, DSOs in FYR of Macedonia and Serbia decided to insure network assets, although equipment insurance is not legal obligation. Insurance policies in both cases cover damages due to natural disasters, such as floods, fires and earthquakes. In Serbia, insurance policy also covers equipment breakdowns. In Bosnia and Herzegovina equipment insurance is not legal obligation and DSOs decided not to insure equipment at all.

Data on average network age for some of the EnC CPs in 2012[48] show that distribution network is particularly old in Albania and Serbia with the average age of 37 years and 33 years respectively. In Bosnia and Herzegovina the average network age is in the range 20-24 years for all DSOs operating in the country, what can be treated as the semi-old distribution networks. Some of the O&M costs increase with the installation's age, thereby due consideration should be given to such circumstances when comparing actual level of O&M costs.

***Regulator may apply a number of methods to decide appropriate level of the controllable O&M costs, whereby a benchmarking is the usually applied method to assess the level of DSO's efficiency and to recognize a reasonable level of costs. Different indicators of average OPEX costs may be applied for comparison purposes such as OPEX/number of connections, OPEX/km of line etc. It is worth to emphasize that different objective conditions should be taken into account by regulator when allowing the reasonable O&M costs, like the network density, share of underground cables, network age, geography and climate conditions.***

### 3.3.1. Costs of goods and services acquired from related parties

It is quite usual that DSOs are sharing some of the services (such as legal, accounting and IT services etc.) with the affiliated companies via specific contracts.

These services should be rendered on the market prevailing conditions and no cross-subsidization should be permitted between related parties. In principle, services or goods procured internally are measured at costs, provided that costs are lower than fair market price. If market price is lower, then market price is applied.

Shared cost may also include overhead costs of the parent company. DSOs are expected to provide allocation keys to allocate the costs of shared services between segments of related parties, which will be subject to regulatory monitoring. Regulators should be authorized to evaluate whether the allocation keys are compliant with the rules related to the cross subsidization and competitiveness.

## 3.4 COST OF NETWORK LOSSES

Average level of losses in EnC CPs is significantly above the EU level. The survey and benchmarking conducted by EIHP and ECDSO-E show that any extreme levels of losses are primarily due to illicit activities such as illegal connections and meter tampering, often in combination with inadequate legal enforcement.

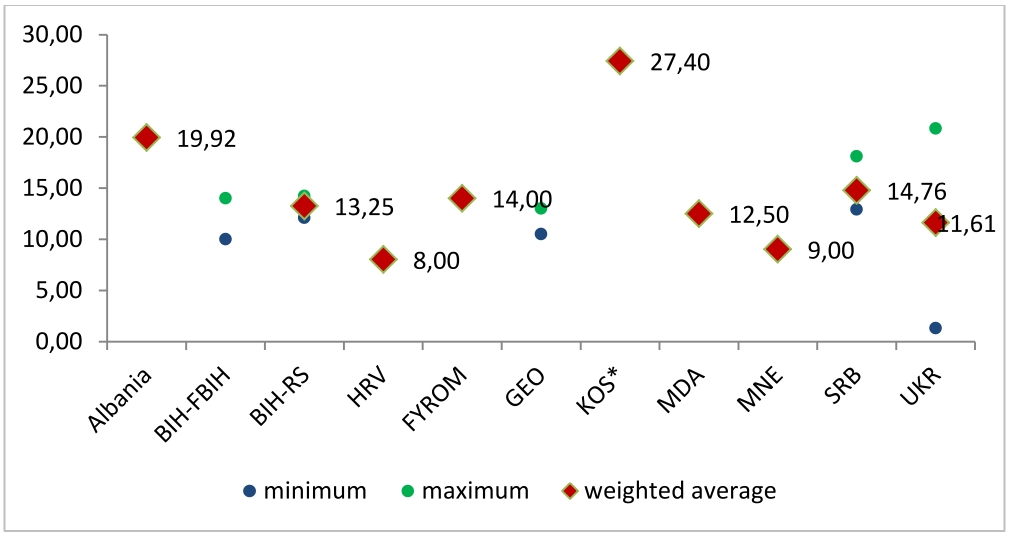
The comparison of level of losses expressed as a single percentage of electricity inputs may be very deceptive, unless the consumption structure per voltage level is taken into account as losses are increasing at the lower voltage level. In the EnC CPs on average 70-75% of electricity consumption in the distribution network (< 110 kV) is at the low voltage level, a much more than in the average of the EU Member States.

[48] EIHP, Southeast Europe Distribution System Operator Benchmarking Study, p. 62

Additional considerations are needed to have the data on the levels of losses fully comparable, such as delimitation between transmission and distribution at the high voltage (HV) level 110 kV, transit flows at medium voltage level, treatment of public lightning and DSO's self consumption. For the benchmarking purposes, if the HV network level 110 kV is part of the DSO network, the electricity supplied through this network should be exempted from analyses.

Average network losses (both transmission and distribution) in Europe and North America are around 7%.

Weighted average level of regulatory approved losses in EnC CPs, as provided in ECRB Study [49], is given by Figure 10.

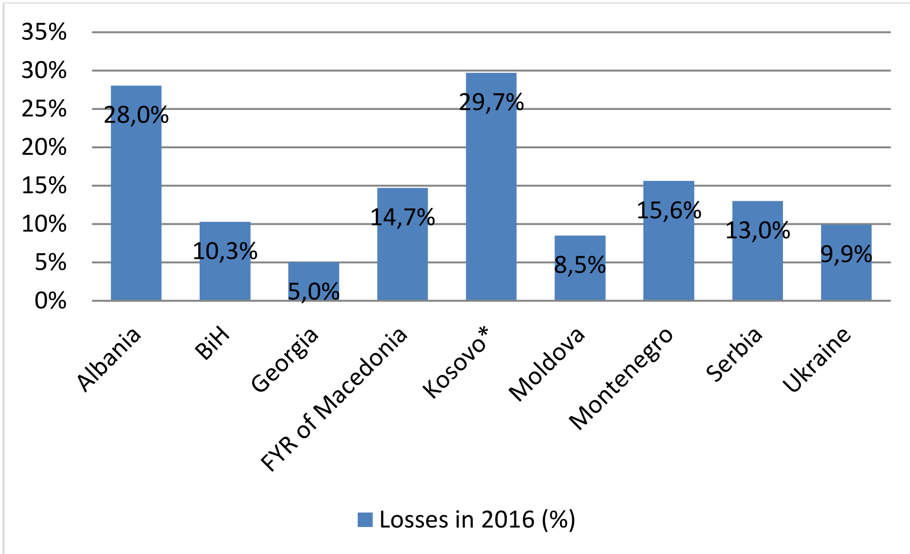



Source: ECRB

**Figure 10** *Allowed weighted average levels of losses in the distribution networks (in %)*

Actual level of losses in 2016 is provided by Figure 11.

[49] ECRB Status Review of Main Criteria for Allowed Revenue Determination for transmission, distribution and regulated supply of electricity and gas, p. 29




Source: EnC Secretariat (Implementation Report)

**Figure 11** *Actual levels of losses in the distribution networks in 2016 (in %)*

### 3.4.1 Non-Technical losses

Analyses of the data provided by Figure 11 shows significant level of non-technical losses in majority of EnC CPs. When regulator does not recognize any of non-technical losses, companies are facing liquidity difficulties which may lead to the bankruptcy.

In spite of the fact that recognition of non-technical losses explicitly conflict the principle of cost reflectivity, certain level of non-technical losses has to be recognized as a transitory measure with limited period of application. Regulators should oblige DSOs to continuously decrease level of losses with the ultimate target to reach the level of best performing companies. Abatement the excessive non-technical losses often require wider consensus and commitment from legislative, judiciary and law enforcement institutions. Economic incentives to reduce electricity losses should be provided by the bonus/malus schemes, allowing DSO to keep savings from losses reduction and vice versa to bear additional costs if the losses are higher than approved level during the regulatory period.

***Treatment of costs of non-technical losses has to be consistent with the treatment of any subsequent revenues, such as the revenues accrued afterwards from detected illicit consumption.***

### 3.4.2 Technical losses

For the technical losses consideration, important provisions are given by the Directive 2012/72/EU (Article 15), requesting the CPs to ensure, by 15 October 2018 that:

- an assessment is undertaken 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,

- concrete measures and investments are identified for the introduction of cost-effective energy efficiency improvements in the network infrastructure, with a timetable for their introduction.

Regulatory measures to decrease technical losses should be oriented to achieve 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 distribution network. For power transformers, basis for design and procurement is given by the Directive No. 548/2014 for implementing the Ecodesign Guideline 2009/125/EG for transformers, obligating the EU countries to exclusively install power transformers with decreased level of losses. 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 solution.

The SEEDT Study[50] estimated the overall losses in EU-27 distribution transformers at about 33 TWh/year. This figure does not include reactive power and harmonic losses which, at a conservative estimate, add a further 5 TWh/year (or 15% of calculated total of no-load and load losses) for all electricity distribution companies and private distribution transformers. Total losses of distribution transformers in EU-27 are therefore estimated about 38 TWh/year. Similar statistics are not available at the EnC level, but those data can be used as a basis for comparative analyses.

Study analyses and recommendations for optimal design of distribution circuits[51], show that optimal circuit utilization should be quite low when costs of distribution losses are taken into account, as given in Table 3.

**Table 3.** *Optimal utilization factors of cables and overhead lines in a typical distribution network*

| Voltage level | Type of conductor | |
|---|---|---|
| | Cable | Overhead line |
| 11 kV | 0,2-0,35 | 0,13-0,2 |
| 33 kV | 0,3-0,5 | 0,17-0,25 |
| 132 kV | 0,75-1 | 0,3-0,5 |

***Technical losses as a matter of regulatory concern should not only be recognized 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.***

[50] Selecting Energy Efficient Distribution Transformers A Guide for Achieving Least-Cost Solutions
[51] Curcic, S., G. Strbac, and X.-P. Zhang, Effect of losses in design of distribution circuits. Generation, Transmission and Distribution, IEE Proceedings, 2001. 148(4): p. 343-349.

### 3.4.2 Country Case Study - Montenegro

In the period 2010-2016, the Constitutional Court of Montenegro made two decisions related to the regulatory rulebook for distribution tariffs setting. In both cases, the Court determined that rulebook is not in accordance with the Constitution and the laws of Montenegro.

The first appeal was submitted by the Ombudsman's office of Montenegro, requesting the Constitutional Court to determine the illegality of the electricity charge related to the costs of transmission and distribution network losses. Ombudsman's explanation was that the Energy Law does not envisage any obligation of end consumer's to pay variable costs of network operators that correspond to the costs of technical and non-technical losses. In addition, explanation contained Ombudsman's position that costs of losses cannot be included in the network services costs and therefore cannot be charged to the end consumers.

The Constitutional Court made final decision on 10 February 2011, stating that regulatory commission had gone beyond its mandate by introducing the costs of network losses as a new charge that was not explicitly prescribed by the Law. In addition, the Constitutional Court declared that principle of legal equality had been violated, since the electricity consumers had to pay a share of non-technical losses linked to the electricity theft. Previous argumentation was a basis for the Constitutional Court to determine that charging the costs of network losses, both the technical and the non-technical, was not in accordance with the Constitution and the Energy Law of Montenegro.

The second appeal was submitted by the group of nine delegates of the Public Assembly of Montenegro and the non-governmental organization, both stating that Regulatory commission had arbitrarily set level of network losses, had illegally introduced the regulatory asset base as a basis for rate of return calculation and had violated the Law on consumers protection (Article 39 prescribing that service provider is not allowed to charge end consumers for the costs of construction, renewal and modernization of distribution network).

The Constitutional Court made final decision on December 26th 2016, declaring non-conformity with the Constitution and the laws of Montenegro and revoking provisions of the rulebook on distribution network tariff setting related to the inclusion of construction work in progress in the regulatory asset base, because the Court had considered this inclusion to be against the previous stated article of the Law on consumers protection. The Court explained that violation was related to the fact that end consumers had been charged for the future costs of network facilities that were not commissioned and were not used at the moment of charging.

The Constitutional Court refused to assess the level of network losses, founding this decision on the Energy Law (which had been changed in the meantime) that explicitly allowed regulatory authority to calculate the costs of technical losses as the part of total costs of network services. In this case, the Court declared that assessment of the approved level of network losses is not a subject of the Constitutional Court competences.

## 3.5 OTHER REVENUES

In addition to the revenues from the network use services, DSOs make additional revenues by providing other services to the network users.

Other revenues can be categorized into the following groups:

- Labor costs used for own facilities construction,
- Connection fees,
- Non-standard consumer’s services (disconnection, metering calibration requested by end user, on-request meter reading etc.),
- Rents,
- Revenues from detected illicit consumption,
- Not categorized revenues.

The principle is that only accrued revenues, other than revenues from network tariffs, shall be recognized as a deductible item in calculation of required revenues provided that corresponding costs are recognized and accounted for determination of the recognized costs. In that sense, revenues from assets sale should not be treated as the other revenues that are to be deducted from the revenue requirements, provided that corresponding costs of asset’s write-off are not recognized. Otherwise, if asset’s write-off costs are recognized, assets sale revenues are to be deducted to prevent DSO in making extra revenue.

Revenues from illicit consumption are linked to the detected illegal consumption of electricity (thefts), when DSO is authorized to invoice estimated past electricity consumption up to the detection moment. Those revenues can make significant share of DSO annual revenues, especially in countries which have high percentage of distribution losses and consequently a large number of detected thefts during the year. Revenues from charges for estimated illicit consumption and/or associated penalties may be deducted provided that respective costs of non-technical losses are recognized and allowed through revenue requirements.

***It is normally expected that regulator will adjust the approved revenue requirement to reflect and deduce other revenues. The calculated adjusted revenue is to be recovered through prices charged for network use services.***

## 3.6 POSITIONS - OPERATING COSTS AND OTHER REVENUES

| | |
|---|---|
| 3.3<br>OPERATING COSTS | Regulatory framework is expected to provide clear definitions of the controllable and the non-controllable operating costs, particularly if incentive regulation is in force.<br>Recognized operating costs should be based on the historical costs, preferably normalized over relatively longer period of at least 3 years.<br>Incentive regulation should be applied to reach the level of operating costs appropriate for efficient running of a network operation.<br>Controllable OPEX should be adjusted for the increments of distribution network length and number of substations during the regulatory period.<br>Allocation keys and prices for shared services with affiliated companies should be subject of regulatory monitoring and approval if necessary.<br>Recurring costs of damages caused by the extreme weather or natural disasters might be provided through the dedicated annual budget, ex-post analyses and approval of actual costs incurred or alternatively through the recognition of equipment insurance costs. |
| 3.4<br>COST OF NETWORK LOSSES | Distribution losses are a separate cost category in relation to the operating costs.<br>Certain amount related to non-technical losses should be recognized depending on the specific circumstances in each EnC CP.<br>Price of energy losses should be based on the reference market price and should reflect the trends at the wholesale electricity market, allowing the DSO to keep the savings if purchase price is lower, or bearing the costs if the price is higher than reference market price.<br>Cost of network losses should be compulsory factor in long term cost-benefit analyses of network investments which should be based on the lowest lifecycle costs rather than on the lowest investment costs. |
| 3.5<br>OTHER REVENUES | Other revenues may include capitalized labor costs, such as those used for own facilities construction, connection fees, provision of non-standard consumer's services (disconnection, metering calibration requested by end user, on-request meter reading etc.), charges for detected illicit consumption, rents and not categorized revenues.<br>Revenues earned by DSO may be included as a deductible item only if the corresponding costs were recognized and included in the calculation of required revenues. |

# 4 INCENTIVE REGULATION

Incentive regulation is advanced regulatory method applied for setting use-of-network tariffs, which involve 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: productive efficiency, allocative efficiency and quality of supply. These objectives may be conflicting and difficult to realize if they are considered separately.

Introducing incentives in regulation is not a new method of regulation by itself, but is rather an amendment to standard regulatory methods used for price regulation. It is recommended to be applied on a granular basis, regarding the following cost's type and performance outputs:

- Operating costs,
- Cost of losses,
- Quality of supply,
- Innovation (research and development).

To make incentive regulation outputs more predictable, regulator should set transparent rules on benefits sharing (also known as a sliding scale) between utility and consumers.

In order to create optimal regulation model, different regulation methods may be applied solely or as a combination.

## 4.1 OPERATIONAL EFFICIENCY

Efficiency target is set by regulator and it is expected that DSO's controllable costs are reduced year by year; otherwise DSO is to bear additional costs. It is important to stress that requirements on higher productivity can not be applied on the uncontrollable costs, since only a part of the operating costs can be subject to the efficiency target. In addition, efficiency requirements are commonly not applied on the capital costs (depreciation and rate of return).

Efficiency requirements are currently applied on CAPEX in 8 out of 24 observed EU Member States and in Norway[52]. Revenue cap regulation method may be applied without efficiency targets imposed on capital costs, in this case CAPEX regulation approach corresponds to the rate of return (cost plus) methodology.

Incentivizing network companies to reduce costs is more complex for CAPEX than for 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 be evaluated since the resulting output is typically realized after several regulatory periods from the one in which the costs are made. Hence the life cycle approach is most appropriate to measure the cost effectiveness of necessary investment.

[52] CEER, Report on Investment Conditions in European Countries, p. 17-18

Initial step for incentive regulation is to establish DSO’s base costs, calculated based on the historical costs in a relatively longer time period, usually of at least 3 years, thereby providing a ”normalized” DSO’s terms of operations. This is to avoid manipulative gaming such as a situation when company limits its cost reduction efforts as getting close to the next price review or manipulates its declared costs or profit to “protect” its realized cost saving. Setting the DSO’s base costs at the level that significantly deviates from the average necessary or normalized costs may further distort the signals about cost-efficiency.

Efficiency rates may be in the form of a general target for all DSOs or in the form of a company specific target, where a combination of both approaches can also be applied. General efficiency targets are used in regulated monopoly markets to replicate the pressure of competition and draw on the ‘’RPI-X’’ approach. Company specific targets that are based on specific performance of each DSO are used to eliminate difference among different operators that have same characteristics.

If company specific targets are used, next step in incentive regulations is to set the reference costs of distribution service. Regulator is expected to provide reference cost-effective DSO(s) based on the benchmarking analyses, whom the respective DSOs are to be compared with. For those purposes yardstick regulation method based on DSOs benchmarking is commonly applied, using different benchmarking methods as the Data Envelopment Analysis or Stochastic Frontier Analysis. Regulation costs are the main drawback of yardstick regulation with DSOs benchmarking, as the model application requires a costly information collection and analysis.

Several geographical and network specific variables should also be included in the model, as the differences in geographical and climate conditions between companies may give different cost levels. Benchmarking model should include factors as a network density, share of underground cables, forest (tree cutting costs), snow, wind, coastal exposure (corrosion) etc. The purpose of including network structure and geographical variables in the model is to make comparison more objective, as the companies with similar conditions should be compared in the analysis.

As an example of very advanced incentive regulation scheme, UK regulator OFGEM has developed the ‘’RIIO model’’ where acronym RIIO relates to ‘’Setting **R**evenue using **I**ncentives to deliver **I**nnovation and **O**utputs’’. This model has been applied for the first time while setting use-of-network tariffs for the regulatory period 2015-2023.

DSO’s allowed revenues are adjusted during the regulatory period on the annual basis, depending on DSO’s performance against incentive mechanisms. The outputs associated with baseline revenues that DSOs must deliver fall into six categories:

- Reliability and availability,
- Environmental protection,
- Connections,
- Customer satisfaction,
- Social obligations (helping vulnerable customers),
- Network safety.

The regulator in Denmark applies an average of the top 10 % most cost-efficiency DSOs to benchmark the cost-efficiency among the remaining 90 % of the Danish DSOs. Based on this benchmarking, regulator sets an annual efficiency requirement for each of the DSOs with a relatively low cost-efficiency compared to the top ten most cost-efficient DSOs. In Sweden, regulator had considered implementation of alternative specific incentive regulatory scheme by which actual O&M costs would be benchmarked against the cost of an engineering designed cost norm model, but this model was not implemented since it was primarily intended to supplement specific capital costs calculation method that was declared to overcompensate DSOs.

Efficiency targets applied in Europe are not fully comparable, as the Czech applies 1,01% (2,031% in the previous regulatory period), Austria 1,25% general target plus the company's specific target, Italy 1,9%[53], Finland 2,06% general target plus the specific target[54], Sweden 1%, Poland 2,38%, Portugal 2,5% (3,5% until 2013), Germany general target 1,25% (1,5% in the second regulatory period) plus the specific target of 10% during the regulatory period, Slovakia general target 3,5%[55]. Nordic countries have a long experience of efficiency targets application in the last 15 years. Standard values of efficiency targets are in the range 1-2%, while both a general and a company-specific X-factor are applied. Sweden apply a general target for all network operators, Finland both a general and a company specific target, while Norway and Denmark use solely a company specific target.

***Operational efficiency incentive regulation is an inevitable part of advanced regulatory methods, where the incentive targets are usually applied on controllable OPEX. Both the general and company's specific targets may be applied, depending on the specific regulatory environment. Once the Regulator assess that regulated utility is sufficiently efficient with regard to the operating costs, incentive regulation may be discontinued, but the regulatory monitoring on operating costs must be continued to protect achieved efficiency level.***

## 4.2 DISTRIBUTION LOSSES

Cost of losses may be treated as the controllable or non-controllable ones depending on the regulatory framework. In countries with the low level of losses (Finland, Sweden), they are standardly categorized as the non-controllable pass-through-costs and thereby excluded from the efficiency requirements. In this case adjustment is made by regulator only if the energy price of losses is changed.

Prevailing regulatory practice is treatment of losses as a controllable cost that is subject to efficiency requirements.

A separate performance based regulation is more appropriate solution for energy losses regulation compared to the losses regulation as a part of DSO's OPEX. This solution enables regulator to set specific incentives to decrease electricity losses, while costs saving may implicitly incentivize DSOs to look for technical solutions which are costly in comparison to conventional technologies, but more cost effective in the long term as a result of cost of losses factoring in.

***In order to provide adequate incentives to DSOs to decrease network losses, revenue cap should not be adjusted downwards if the physical losses go down during the regulatory period, thereby allowing***

[53] CEER Report on Investment Conditions in European Countries, p. 17-18
[54] EURELECTRIC, Electricity Distribution Investments: What Regulatory Framework Do We Need, p. 18
[55] E&Y, Mapping power and utilities regulation in Europe, p.19

***DSO to get the whole benefit of less physical losses on the grid and vice versa to bear additional costs if losses are increased.***

## 4.3 QUALITY OF SUPPLY REGULATION

Quality of supply regulation is a supplement to operating costs based incentive regulation and its aim is to prevent regulated companies to reduce operation and maintenance costs to the detriment of quality of supply. This kind of regulation may even be considered as an obligatory complement to other forms of incentive regulation that are requesting costs reduction. Otherwise if the quality of supply regulation is not applied, incentive regulation pursing the costs saving would eventually result in the long-term deterioration of quality and security of supply as well.

Therefore, a main purpose of quality of supply regulation is to provide incentive to regulated utility to at least maintain, but also improve the regulated quality parameters.

Currently, out of nine EnC CPs, only in Moldova quality of supply parameters are incorporated into the network tariffs regulation.

In theory, the best regulation method is the method that is capable to reflect economic value of quality of supply where, as a general rule, reward for better performance covers the incurred cost of improving quality and penalty corresponds to the consumers' social losses in term of quality degradation. But this is not an easy task as determination of the link between the quality of supply improvement/deterioration, incurred costs for quality improvement and the consumers' benefits/costs is a complex issue requiring a complex study. Quality improvement costs include feeder automation, overhead lines replacement by underground cables, replacing light with heavy constructions overhead lines, increase of number and mobility of fault repairing crews, management of spare parts etc.

Quality of supply regulation is in principle based on the continuity of supply parameters System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), while advanced regulation schemes apply the Energy Not Supplied (ENS) parameter. Historical statistics of SAIDI and SAIFI parameters are generally available for a sufficiently long period to provide reliable basis for QoS regulation. The costs of energy not supplied describe the costs the consumers incur because of electricity supply outages. Those costs may be calculated based on the relevant study on the value of lost load or through the consumer's survey including the different perception of outage valuation per consumer's classes.

It is recommended that quality of supply regulation is gradually introduced and moved towards the more advanced methods. The good practice observes the following steps:

- At the very initial phase, incentive regulation should be based on SAIDI and SAIFI parameters. In parallel, guaranteed standards should be introduced to protect individual consumers from excessive outage duration.
- In the next phase, the ENS parameter and its value may be introduced in order to properly quantify socio-economic costs of outages.
- In the final phase, the "worst served customer" regulation should amend the ENS regulation to properly protect and to guarantee minimum quality to all consumers in situation when high quality of supply is achieved at the DSO level in average.

Once the regulation parameters are decided, following steps are needed to make the scheme operative:

- Initial step is to decide which DSO's economic parameter is to be adjusted depending on the difference between actual and reference levels of continuity of supply. Regulatory framework should prescribe which parameter is to be used as a basis for adjustment, out of following alternatives: total revenues, rate of return or operational costs.
- Next step is to set the reference levels of continuity of supply parameters that are used as basis for comparison, usually reflecting the past utility's performance.
- Weighting factors of different types of interruptions should be laid down for unplanned interruptions, planned interruptions and interruptions caused by third party. Different weighting should reflect different costs and responsibilities linked to the specific category of interruptions.
- Regulator should set the reasonable targets for each continuity parameter that is subject of regulation.
- The ceiling and the floor for monetary adjustment should be set to limit the maximum reward the company will receive for better quality, but also to restrict the too harsh negative consequences for network operators in case of worse quality.
- Regulator should set the principle of sharing the socio-economic benefits (sliding scale) of increased quality of supply between network operators and consumers.

Compensation related to the deviation of actual quality parameters and the reference values is performed on ex-post basis, comparing the outcome of quality during the previous regulatory period and setting the adjusted revenue in the next regulatory period.

If guaranteed standards with consumer's compensation are applied for maximum duration of single outage, those outages longer than the threshold value should be excluded from the quality of supply regulation, as there is already an incentive to reduce these interruptions. Interruptions caused by exceptional events and the Force Majeure should also be excluded from the quality of supply regulation.

As an example, Denmark applies the operational costs as a basis for adjustment and DSO can be penalized with up to 2% reduction depending on the level of SAIDI and SAIFI parameters (1% + 1% respectively)[56]. Reference levels of SAIDI and SAIFI parameters are weighted parameters of DSOs holding 80 % of the distribution network. Netherland sets the quality factor bonus or malus at a maximum 5% of regulatory revenue, while Spain sets this parameter at 3%[57].

Norwegian example is provided here as an example of very advanced quality of supply regulation model. Incentive regulation on continuity of supply is integrated in the economic regulation through inclusion of the CENS element (CENS – cost of energy not supplied) in the revenue cap. The customers' costs related to interruptions are assessed through nationwide surveys and vary between different customer groups, when the interruptions occur etc. The net effect of the inclusion of the CENS element in the allowed revenue cap is that the customers are indirectly compensated for 60 % of the socio-economic costs related to poor quality of supply through lower tariffs in the future.

In Sweden quality deduction or premium in the revenue cap are limited to the 3 % of total revenue. The slope of the line between the ceiling and floor values is set to 45 grades, meaning that half of the better quality is given to the customers in terms of better quality and the other half goes to the company as a

[56] NordReg, Economic regulation of electricity grids in Nordic countries, p. 38
[57] E&Y, Mapping power and utilities regulation in Europe, p.21

reward for better quality. In Finland a half of the difference between actual disadvantage costs caused by outages in electricity supply and the reference level of outage costs which is taken into account in the calculation of actual return on network operations, may correspond with a maximum of 20 % of the post tax return in the year in question. This applies to both the floor and the ceiling levels.

***Performance-based regulation method seems to be the most suitable for quality of supply regulation as it provides direct link between a financial reward/penalty and utility's performance. In some cases Regulators also use the yardstick regulation method for those purposes.***

## 4.4 INNOVATION INCENTIVES

As a general rule, a lot of R&D project have to be conducted to manage a few of them to become commercially viable projects. Investments in research, development and innovative technologies are costly and highly risky from the investor perspective as the projects may fail causing some assets to be stranded. Without incentive scheme companies have no stimulus to invest in R&D project as they are looking to meet cost efficiency objectives and to increase cost savings.

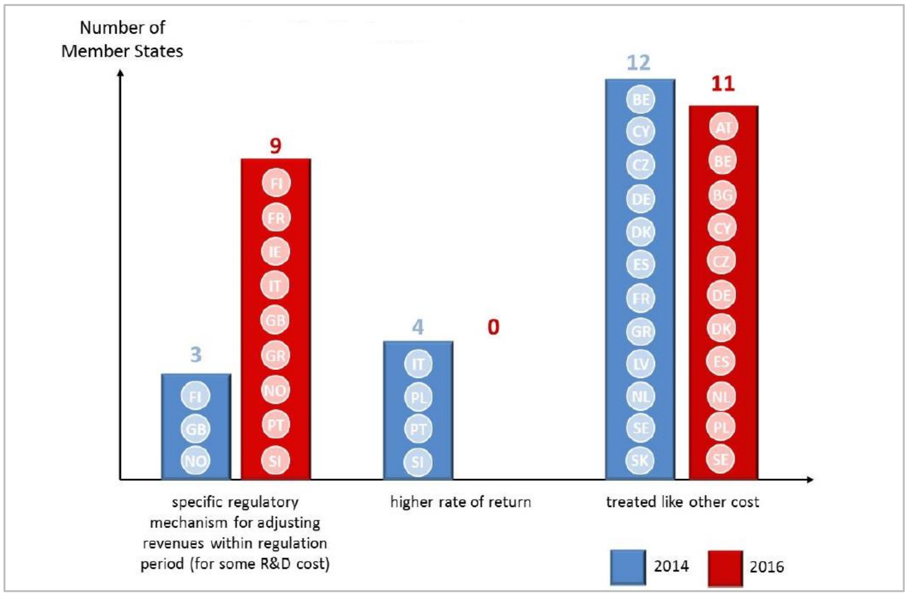
Regulators are pushing DSOs to undertake R&D spending and to invest in new technologies to reflect new regulatory objectives related to improved network operation, long term efficiency, development of smart grids, integration of Distributed Generation (DGs), demand side response etc. In that sense, remuneration of the expenses related to the innovation should be guaranteed.

Innovation could be incentivized either by setting the rate of return on capital high enough for innovation investments extra risk or by applying a specific ad-hoc scheme.

Innovation schemes may be applied in different operational and technological areas such as smart meters, smart grids, network storage, new cable technologies, advanced network monitoring and control, dynamic cable rating, voltage regulation in presence of DGs, electric vehicles charging systems, power flows optimization, innovative tariff design etc.

The survey conducted by EURELECTRIC[58], has revealed that nine out of twenty observed EU countries were applying specific mechanism to incentivize innovation in 2016. Number of countries has increased since 2014 when seven countries had innovation incentives schemes in force. It is important to notice that smart meter projects are excluded from analyses.

[58] EURELECTRIC, Innovation incentives for DSOs – a must in the new energy market development




Source: EURELECTRIC

**Figure 12** *Innovation schemes in observed EU Member States*

Four Member States in 2014 provided incentives through the higher rate of return, while in 2016 there is no single country applying this model of innovation promotion. All of them apply specific regulatory mechanism for revenues adjustment. In addition, with regard to the operational expenditures, currently four Member States (Ireland, Finland, France and UK) apply incentives for OPEX related to innovation.

Currently there is no single EnC CPs that allows funding for research, development and innovative technologies.

From the DSOs perspective it is very beneficial if incentive is given through specific regulatory mechanism rather than by higher rate of return, as the project financing is secured through the advanced funding and there is no time lag between investment and its long term recovery through depreciation. Risk of project failure and assets stranding is also eliminated if investment is realized from dedicated budget.

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

As an example, a very relevant issue for all DSOs in the region is a voltage regulation in presence of DGs. Problem of real time voltage regulation is generally resolved at the planning stage using the conventional deterministic method which is based on the most onerous power flows case (with low probability of occurrence) in the network with regard to the voltage variations. In such cases, alternative solution for grid reinforcement costs that are needed to resolve the problem of voltage variations may be promotion of advanced methods for real time voltage regulation, which may increase hosting capacity without the need for network reinforcement.

***Most R&D projects are OPEX intensive, but these costs cannot be treated as the part of other controllable costs subject to incentive regulation.***

## 4.5 POSITIONS - INCENTIVE REGULATION

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| GENERAL | Taking into account the current state of distribution network tariffs regulation in EnC CPs, incentive regulation is recommended to be introduced in two transitional steps:<br>• At the first phase, costs of distribution losses and simple innovation incentives scheme should be introduced,<br>• During the second phase, elements of incentive regulation for the operational efficiency and quality of supply should be incorporated.<br>Time period between two steps should be sufficient to provide additional time for preparatory works which are necessary to provide coherent regulatory framework.<br>Regulators should not seek claw-back and should allow DSO to retain the efficiency gains during the current regulatory period including operating costs savings under the incentive schemes and the reduction of physical network losses. |
| 4.1<br>OPERATIONAL EFFICIENCY | Efficiency requirements should only be applied on the controllable operating costs.<br>Efficiency rates may be in the form of a general target applied for all DSOs or in the form of company specific targets, while combination of targets is also applicable.<br>Efficiency rates should be calculated on the basis of the local and international DSOs benchmarking, taking into account several geographical and network specific variables.<br>Incentive regulation should be terminated once the 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 DSO to decrease costs. |
| 4.2<br>DISTRIBUTION LOSSES | The costs of losses should be treated as the controllable costs, whereas the level and type of incentives are designed depending on the cause and level of losses.<br>Recognition of appropriate level of losses should be based on the historical performance adjusted by targeted improvement factor.<br>Incentives for losses reduction should be provided by allowing DSOs to receive benefit/costs if actual performance is better/worse than the approved level during the regulatory period, without any ex-post revenue adjustment.<br>When target level of losses is achieved, the incentive for loss reduction should be terminated and any further measure for reduction has to be based on the cost benefit analysis and overall cost effectiveness of the measure. |
| 4.3<br>QUALITY OF SUPPLY REGULATION | Quality of supply regulation should be introduced in parallel with the enforcement of operational efficiency regulation.<br>Quality of supply regulation would not be feasible unless the rate of return is properly addressed and allowed, otherwise implementation of penalty schemes might jeopardize DSO's financial stability.<br>Performance-based regulation method is the most suitable method to be applied for |

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| | quality of supply regulation.<br><br>The financial reward/penalty might be expressed as a percentage of the allowed revenue or the allowed rate of return, with the ceiling and the floor values for monetary adjustment.<br><br>The principle of ex-post sharing the benefits of quality of supply performance between network operators and consumers should be established.<br><br>Quality of supply regulation should be based on SAIDI and SAIFI continuity parameters during the initial phase of scheme implementation.<br><br>Weighting factors for different types of interruptions should be laid down for unplanned interruptions, planned interruptions and interruptions caused by third party, to reflect different costs and responsibilities related to each type.<br><br>Once the appropriate level of quality of supply is achieved, as assessed by regulator, incentive regulation might be reconsidered regarding the improvement targets application. |
| 4.4<br><br>INNOVATION INCENTIVES | Specific regulatory mechanism for innovation, research and development promotion (R&D) through dedicated annual funding is appropriate to incentivize DSOs to undertake these activities.<br><br>Once the promoted technology becomes commercially viable and mass deployed, it should be treated as any other DSO investment.<br><br>Innovation incentives should be introduced through simple not expensive pilot models at the first phase with gradual increase of complexity and funding allowance.<br><br>Both the capital and the operating expenses are to be allowed by dedicated R&D budget, whereas any capitalization of the R&D costs in the RAB must be reflected in corresponding revenues. |

# 5 INVESTMENT MONITORING AND INCENTIVES

DSOs are going to meet demanding investment needs as a result of aging infrastructure, uneven demand growth and integration of rapidly growing distributed energy resources (DER), smart grids with smart meters roll out and strict regulation of security and quality of supply.

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

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

Prudency tests as a part RAB valuation process may also cause utilities to postpone or even cancel some investments, as there is a risk that those investments are not going to be approved by Regulator.

## 5.1 NETWORK DEVELOPMENT PLANS

Network development plans prepared by DSOs may be subject of regulatory approval, or alternatively may be submitted to the regulatory authority for information purposes only.

Regulatory approval of the investment plan may be construed as the ex-ante approval of assets inclusion in the RAB. In addition, approval of distribution network investment plan requires dedicated regulatory staff and huge number of man-days, thereby increasing administrative burden, workload and costs of regulation. Furthermore, the investment plan approval would necessitate much more information provided by the DSO, while assessment of individual investments is likely to draw in the regulator into the activities that are sole responsibility of DSO's management.

It is therefore not necessary that regulator approves network development plans, unless the DSO is a part of vertically integrated company and additional regulatory control is needed to ensure DSO's compliance with the rules related to non discrimination and cross subsidization. If DSO is not a part of vertically integrated company, regular reporting might be sufficient regulatory tool to provide continuous monitoring of network investments.

However, regulators should be authorized to assess whether the individual investment can be treated as a prudent investment on a case-by-case basis. The assessment can be performed for a few selected investments as a part of regular regulatory monitoring duties, or alternatively in situation when regulator deems it necessary to perform assessment for specific individual investment.

Regulatory monitoring of investment realization should be used to indicate the occurrence of both the overinvestment and the underinvestment effect, thereby providing an early indication that additional regulatory measures should be undertaken. For that purpose, regulatory framework may also include mechanisms that prevent over investments and entering of operating costs in DSO's accounts as the capital costs.

***Regarding the investment plans, regulatory focus should be more oriented towards the performance outcomes related to the security of supply, continuity of supply and voltage quality. As long as the performance indicators are being improved in line with the regulatory targets, regulator should refrain from interfering the DSO's investment activities.***

## 5.2 INVESTMENT INCENTIVES

DSOs total revenues are expected to provide sufficient amounts for investments in new and existing facilities. Regulatory tools to promote and incentivize investments in distribution network can be divided in the risk mitigating measures and rewarding mechanisms.

The key drivers to provide investment incentives are:

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

Stability and predictability of the regulatory framework is perceived as a critical precondition for sustainable network development, as it represents a key risk mitigating measure which provides certainty of capital cost recovery over the whole lifetime of the investments. On the contrary, in the case of political uncertainty or instability of regulatory framework, DSOs might postpone or even cancel some investments, while a credit costs for investments in regulated infrastructure may increase and investors might refuse to provide capital to DSOs.

Frequent and adverse changes of regulation regarding capital cost recovery mechanisms (RAB and WACC), too long assets' lifetime for regulatory depreciation purposes, lack of volume risk protection and capital costs valuation based on non-comparable benchmarking are perceived as the riskiest activities which violate stability and predictability of the regulatory framework. Longer regulatory periods are generally perceived as improving stability of regulatory framework, since a possibility of changing regulatory conditions between two proceedings is diminished.

In comparison to the other regulation methodologies, the rate of return regulation method applied for CAPEX determination provides investors with the highest level of certainty that their costs will be fully recovered with some level of guaranteed profit.

Investment activity is directly dependent on DSOs achieved return on capital in comparison with the cost of capital employed to finance RAB. If company is not profitable, shareholders are not incentivized to further invest as cost of capital is not expected to be recovered. A fair rate of return is expected to include specific market risk premium in addition to properly assessed risk-free rate and debt premium. However, setting a fair rate of return is not a guarantee per se that profit will be achievable due to overall complexity of DSO's revenue regulation and recovery.

Non-achievability of the regulated rate of return is even observed in a number of EU Member States, as a result of not performable efficiency requirements and ''CAPEX time shift problem''.

EURELECTRIC survey[59] has revealed that in 14 out of 17 countries DSOs had observed a non achievability of efficiency requirements and a negative effect on the realized rate of return.

There are a number of reasons why efficiency requirements may not be achieved, especially if they are continuously applied in a longer period. Efficiency target if being set at an overambitious level is hardly to be complied. Furthermore, DSOs are not capable to endlessly increase operational efficiency and regulator has to assess when this level becomes satisfactory with no reasonable purpose to further

[59] EURELECTRIC, Electricity Distribution Investments: What Regulatory Framework Do We Need, p. 17

request DSO to decrease costs. Non recognized R&D costs may be additional reason of non achievability as they contain a large share of operating costs that may influence realization of the total OPEX.

‘’CAPEX time shift problem’’ is used to denote a delayed recognition of capital expenditures which may lower the achievable rate of return. In other words, problem relates to the delay between investments and the integration of the resulting capital expenditures within the revenue cap. This problem is resolved in the vast majority of EU Member States according to the EURELECTRIC analyses, except in Netherland, Denmark and Slovakia. A problem is addressed through regulatory mechanism such as the revenue cap combined with the planning cost approaches or the hybrid regulation model with the rate of return regulation of capital cost.

The level of investments is also influenced by the regulation method applied. The analyses of German regulation model[60] has revealed that implementation of incentive regulation has a positive impact on utility’s total investment. Analyses also revealed the existence of the so called ‘’base year effect’’ when utilities are increasing their total investments in the base year in order to increase the RAB value for the following regulatory period and to maximize the discounted sum of future profits. This effect is likely to occur when regulatory price reviews happen at fixed intervals that are known in advance and the utility is in situation to optimize its investment decision and costs.

***Investment incentives are generally provided at the system level, through the appropriate regulatory mechanisms related to the depreciation policy and return on invested capital (both the allowed and achieved).***

## 5.3 REGULATORY ASSESSMENT

Regulator may decide to conduct an assessment of the investment as a part of the RAB approval procedure. This task may be performed ex-ante, by approving the regulated utility’s investment plan and ex-post when assessment is undertaken to supplement the ex-ante investment reviews.

During the ex-post assessment regulators aim to identify differences between the capital expenditures allowed in the ex-ante review and the actual investments undertaken by the company.

Regulatory ex-post assessments can also be undertaken without any previous ex-ante approval of the investments. In this case, the regulated companies are faced with the uncertainty whether the undertaken investments will be included in the RAB, thus the company is incentivized to only undertake efficient investments.

Regulatory assessment may be performed regarding the investment prudency and ‘’used and useful’’ concept. Prudent means that investment fulfills 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 adopt methodology to evaluate planned investments regarding their feasibility, network security, quality of supply impact and non-economical criteria assessment.

[60] Astrid Cullmann and Maria Nieswand, Regulation and Investment Incentives in Electricity Distribution, An Empirical Assessment

An example of prudency test is given by Energy Regulators Regional Association (ERRA) publication[61], stating that actual capital cost shall be included in the capital base provided that:

- The amount does not exceed the amount that would be invested by a prudent network service provider acting efficiently in accordance with good industry practice and to achieve the lowest sustainable cost of delivering services; and
- One of the following conditions is satisfied:
  - The anticipated incremental revenue generated by the capital expenditure exceeds the investment cost;
  - The network service provider can satisfy the regulator that the new capital expenditure has system wide benefits that in the regulator's opinion justify its inclusion in the capital base; or
  - The new capital expenditure is necessary to maintain safety and integrity in the system.

When deciding if the investment is a prudent one, regulator may face difficulties regarding the decision making perspective. One option is that the investment is considered prudent if it was prudent at the time the decision was made. Alternative approach is to assess that the investment is prudent if management acted to minimize costs by fully considering changing conditions that would affect the investment. In the first case regulator should accurately assess what information management had available and used to make its decision, while in second case assessment should comprise what management should have known and should have considered in making its decision.

To add a complexity into a potential assessment, it is worth noting that increasing share of DSOs' investments is driven by the environmental and security of supply goals, whereas quantification of benefits may be difficult from pure DSOs perspective.

Different regulatory practices in relation to the new investments are observed, while some regulators perform ex-ante checks and some do the ex-post analyses without previous approval of investment plans. The existence of ex-post assessment with possibility that a project may be declared inefficient is also a disincentive for investor that brings additional regulatory risk. Regulators' ability to assess investments is usually limited, as regulators may lack expert knowledge and resources and do not always have access to full information and conditions regarding the investment. On the other hand, regulator can not generally agree that all investments would be recognized in the RAB.

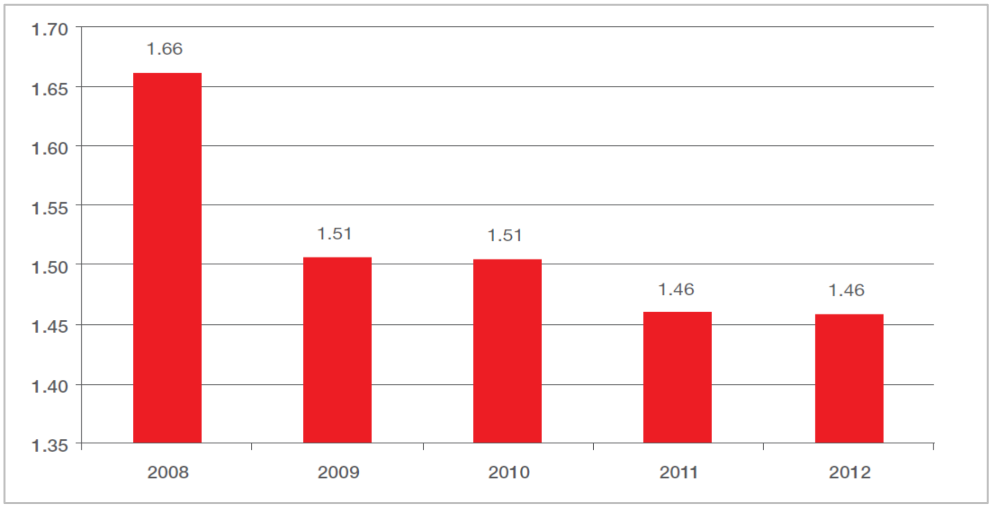
***If applied, regulatory assessment of network investments should be based on the transparent criteria related to the cost effectiveness, security of supply and quality of supply, fully respecting the energy policy other objectives such as social cohesion, environmental protection, energy efficiency etc.***

## 5.4 ACTUAL INVESTMENT LEVEL

As an indicator of DSOs investment activity it is possible to use *capital expenditure/depreciation ratio.* The capital intensive nature of the electricity industry implies that electricity companies have on average higher capital expenditure (amount invested in acquiring new fixed assets) to depreciation ratios than other sectors. Values well above unity are not unusual.

[61] ERRA Tariff and Pricing Committee, Determination of the Regulatory Asset Base after Revaluation of License Holder's Assets, p. 18

A capital expenditure/depreciation ratio for 17 EU Member States and Norway in the period 2008-2012 is shown in Figure 13[62].

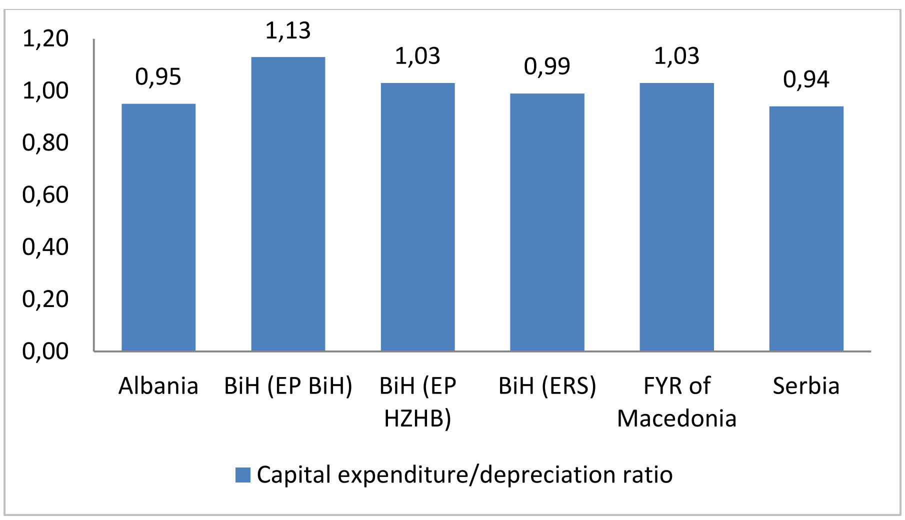



Source: EURELECTRIC

**Figure 13** Capital expenditure/depreciation ratios in observed European countries

A falling trend of investment activity, as explained by EURELECTRIC, is a result of poorer economic performance and pressures from credit rating agencies and equity markets.

Contrary to the investment statistics recorded in Europe, capital expenditure/depreciation ratio in the EnC CPs is close to the unity value in the period 2008-2012. Figure 14 shows the statistics for six EnC DSOs where data are available[63].




Source: EIHP, Southeast Europe Distribution System Operator Benchmarking Study

**Figure 14** *Capital expenditure/depreciation ratios in observed EnC CPs (2008-2012)*

62 EURELECTRIC, Electricity Distribution Investments: What Regulatory Framework Do We Need, p. 12
63 EIHP, Southeast Europe Distribution System Operator Benchmarking Study, p. 241

It is worth to note that level of replacement investments can have yearly variations and replacement investment surplus or deficit may occur during the regulatory period.

## 5.5 POSITIONS - INVESTMENT MONITORING AND INCENTIVES

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|---|---|
| 5.1<br>NETWORK DEVELOPMENT PLANS | Regulatory approval of DSOs network investment plans is recommended provided that the DSO is a part of vertically integrated company, otherwise regular monitoring over the investment's activities might be adequate regulatory tool. .<br>Regulatory focus towards the performance outcomes, such as efficiency improvements, or targets related to the security of supply, continuity of supply and voltage quality are deemed to be the better means than the assessment whether the individual investment can be treated as a prudent investment to be included in the RAB. |
| 5.2<br>INVESTMENT INCENTIVES | Investment recovery and stimulus for new investments should be provided through:<br>• Stability and predictability of the regulatory framework,<br>• Fair rate of return on investments,<br>• Achievability of the regulated rate of return.<br>Frequent and adverse changes of regulation regarding the capital cost recovery mechanisms (RAB and WACC), too long assets' lifetime for regulatory depreciation purposes, lack of volume risk protection and capital costs valuation based on non-comparable benchmarking should be avoided due to their undermining effects on stability and predictability of the regulatory framework.<br>The rate of return achievability should be reasonably provided, for that purposes overambitious and too long operational efficiency schemes should be avoided.<br>Investment costs recovery and network extension and reconstruction should be ensured by consistent depreciation policy and appropriate rate of return allowed. |
| 5.3<br>REGULATORY ASSESSMENT | 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 life span of an asset.<br>Criteria for recognition of investment costs should be based on the cost effectiveness, security of supply and quality of supply parameters, but should also include the other non quantifiable energy policy objectives such as social cohesion in general and within the local communities, environmental protection, energy efficiency and other objectives of the energy policy.<br>Criteria applied by regulator to evaluate the prudency and reasonableness of the 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. |

# 6 COSTS ALLOCATION AND DESIGN OF NETWORK TARIFFS

## 6.1 INTRODUCTION

The appropriate structure of charges for distribution services is a complex issue, usually not based purely on the technical and economical parameters of the distribution services, as it also takes into account social acceptance, administrative costs, feasibility of pricing system implementation, low income consumers protection etc. As there are a number of underlying principles of tariff design, a reasonable trade-off is needed for conflicting objectives. General rule is that tariffs charged to customers should be cost reflective in a way that they fairly reflect the costs associated with their use of the system. Some level of cross subsidization among the consumers within the same class is inevitable as the same tariffs are applied for consumer's classes that involve consumers with different load profiles.

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

For a demand side management measures to be unlocked, there is a need to have more complex tariff structure with the Time of Use (ToU) differentiation depending on the season and/or time of day. Otherwise customers' response and consequently load shifting is hardly to be expected on a large scale. Distribution network ToU tariffs should not counteract the transmission services and energy supply ToU prices, as they should be fully aligned in order to avoid opposite or conflicting signals for consumers.

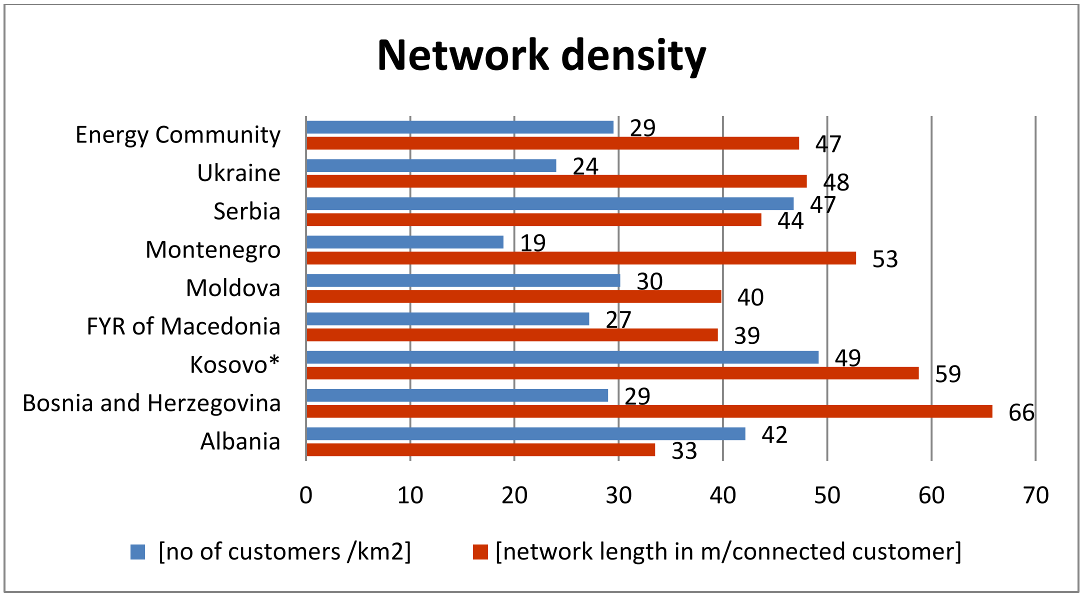
When tariffs for distributed energy resources are considered, a special attention should be paid to the principles of the fairness, cost reflectivity and cost recovery, particularly if the simple volumetric tariff rate design is in use. Growing trend of PV installations for self consumption purposes has increased the uncertainty of cost recovery, but also undermined the principles of fairness and cost reflectivity. Reform of rate design to ensure that those who use the grid also pay for its use opened the complex question from whom the costs will be recovered.

Tariff design is expected to provide revenue stability, particularly in situation when load forecasting becomes more difficult with the fast deployment of new technologies causing the change of consumer's load profile. Degree of certainty in recovering full costs of service is a critical issue from the utility's perspective.

Tariff design and tariff rates can also be seen as a regulatory tool to influence investment decisions regarding energy efficiency, demand response and distributed generation.

## 6.2 NETWORK STRUCTURE AND DESIGN

Distribution network structure can be described by a set of typical indicators which provide insight into the prevailing field conditions in specific country. First set of parameters which relates to the number of consumers per $km^2$ and network length per connected consumer is provided in Figure 15.

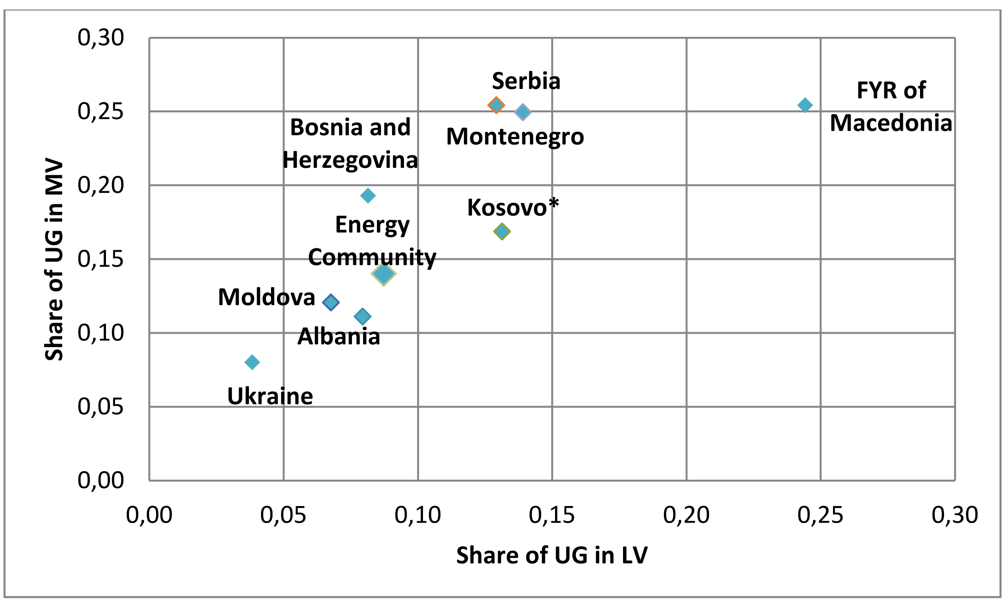



Source: ECDSO-E collection (EnC Secretariat database)

**Figure 15** *Network densities in EnC CPs*

As shown in Figure 15, significant variations exist among the CPs, but a general correlation between lower consumer's density and longer network length per consumers is obvious. Those parameters directly impact the DSOs average O&M costs and should be taken into account when making benchmarking analyses.

Second set of parameters relates to the share of underground cables in total network length for MV and LV distribution network. Data for EnC CPs are provided in Figure 16.

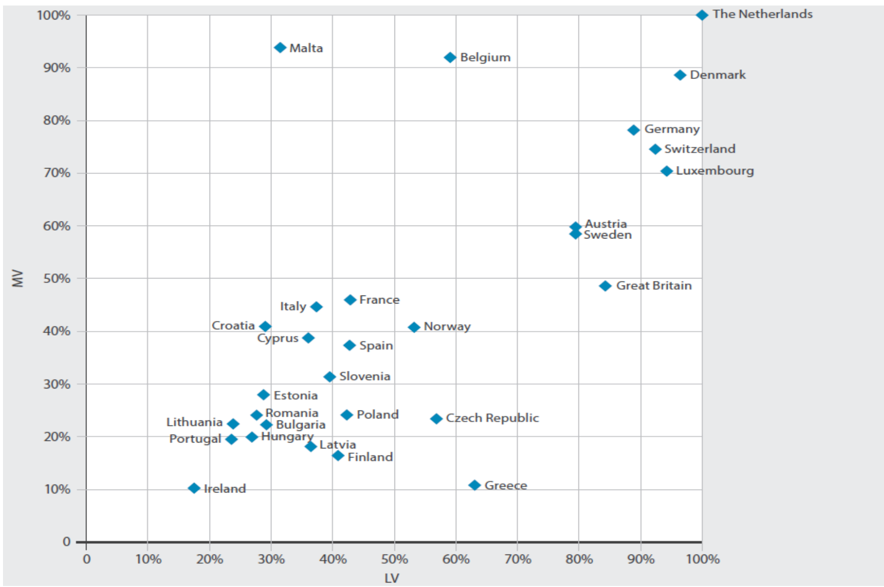



Source: ECDSO-E collection (EnC Secretariat database)

**Figure 16** *Share of underground cables in distribution network in EnC CPs*

Share of underground cables in both the MV and the LV distribution network is quite low, with the parameters of the best scoring country (FYR of Macedonia) in the range of the worst EU Member States regarding the network structure. Network structure data are indispensable part of DSOs benchmarking, as they directly influence the level of capital costs, O&M costs and quality of supply. The higher share of underground cables causes the higher average capital costs (per km), but decreases the O&M costs and improves the continuity indicators. DSOs benchmarking without network structure adjustment would be deceptive and could lead to the wrong conclusions regarding the DSO's operational efficiency.

Network structure data for EU Member States and Norway are provided in Figure 17[64].




Source: CEER

**Figure 17** *Share of underground cables in EU Member States and Norway*

Underground cables share in EU Member States and Norway is well above the average figures in EnC, what represents one of the key reasons for better quality of supply indicators in these countries in comparison with the EnC CPs.

## 6.3 TARIFF COMPONENTS

Distribution service tariffs can be grouped into the five main types:

- Connection fee (€/kW) or (€) for new connections;
- Demand – capacity charge (€/kW);
- Volumetric (or energy-based) variable charge (€/kWh);
- Fixed charge (€/metering point per month);
- Reactive energy charge (€/kVArh).

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

64 CEER, 6TH Benchmarking Report on the Quality of Electricity and Gas Supply, p. 49

The pricing of use-of-network services could be based on a fixed charge (per metering point per month), a variable charge (per kilowatt-hour), a demand charge (per kilowatt) and a reactive charge (per kVArh) or some combination of these.

The fixed component is a fixed monthly amount that covers customer-specific costs. These include costs related to metering, settlement, invoicing, service centers etc. This part of DSO's costs should not exceed the costs attributable to an incremental consumer.

The energy component depends on consumption and shall at minimum cover costs of marginal loss (the loss that occurs when one extra kilowatt-hour is taken out, at a given load) in the network.

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

A demand charge recovers some portion of the allowed revenue through a price that is based on a measure of the customer's maximum demand for electricity (kilowatts). Maximum demand for the billing purposes can be defined as a 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. A consumer class contribution to power system peak demand is usually factored in the calculation and allocation of costs to be recovered through demand charges from each consumer class.

Historically, demand charges have been implemented for commercial and industrial consumers based on the individual peak demand of each consumer, regardless of whether it occurs during system peak periods. Such a pricing scheme is a relatively simple, but it hides some level of cross subsidization as consumers whose peak demand is not peak coincident pay a grater share of cost, while those who contribute to the system peak demand bear a lesser share of capacity driven costs.

Reactive energy charge is used to encourage network users to use the distribution network efficiently with power factor as close to unity as possible. An excess reactive energy consumed below a certain power factor threshold is usually invoiced to consumers. When power producers are considered, treatment of reactive energy becomes more complex, as described in section 6.6.4.

The reactive energy unit price generally reflects the value of the reactive power generation and voltage regulation equipment and the additional cost of network losses due to reactive power flows, as well as pass-through costs of TSO charges for excessive reactive energy of respective DSO as a transmission system user.

Charges for excessive reactive energy consumption are commonly applied in the Energy Community. Consumers with appropriate equipment for reactive energy registration may be fairly charged for the incurred underlying costs. However, it becomes a demanding task to identify and fairly allocate the costs of reactive energy to consumer categories without such equipment, e.g. households, as their consumption patterns are changing with deployment of new appliances, such as air conditioners.

DSOs have two approaches at hand. The first approach is not to permit consumption below determined power factor given by the general terms and conditions and network code. In case of lower power factor then defined, the consumer shall be charged for the consumed reactive energy in the form of penalty. If deviation is allowed and reactive energy is defined as a regular tariff rate, charges for reactive energy should reflect the marginal costs to keep power system voltages within the permitted tolerances.

The costs of reactive power energy should be fairly assigned to all consumer categories in accordance with their power factor. For consumers without reactive energy registration, these costs should be determined and assigned to the tariff rate for delivered active energy.

From the perspective of DSO, system stability and fairness, the preferred approach is to request all consumers to abide to the defined power factor and to ensure for it in the connection design and connection contract.

## 6.4 ALLOCATION OF NETWORK DEVELOPMENT COSTS, TERMS AND CONDITIONS FOR CONNECTION

The issues of the use-of-network tariffs and connection tariffs can not be considered separately, as the level of connection tariffs directly influences the revenue share to be recovered through the use-of-network tariffs.

Total DSO revenues from connection and network use services should provide sufficient cash flow to finance network development investments including connection assets. Share of end user's contribution to the network development investments depends on the connection charging regime.

The following definitions given by European Network of Transmission System Operators for Electricity (ENTSO-E) can be used to classify connection charges although some connection charges do not fall exactly within this classification:

- Super-shallow: All costs are socialized through the use-of-network tariffs, no costs are charged upfront to the connecting entity,
- Shallow: network users pay for the infrastructure connecting its installation to the electricity network (line/cable and other necessary equipment),
- Deep: shallow + all other reinforcements/extensions in existing network, required in the electricity network to enable the network user to be connected.

Connection charges have a significant impact on the ability of new participant, particularly power producer to enter the market. In that sense regulatory framework may favor the increase of installed DG capacity through the shift toward the shallow connection regime. In that case missing revenues recovery is provided through increased use-of-network tariffs.

The implications of different connection charging regimes become more evident when incremental network development costs are rising:

- In a system with little spare network capacity and high growth, incremental costs might be high, so a shallow connection charging would have a significant impact on other end users,
- In a system with spare network capacity, incremental costs might be low.

Connection tariff (connection fee) charged for a new connection may be defined as a fixed amount, as a variable capacity driven charge, or as a combination of these methods. Furthermore, connection charging regime may differ for consumers and for power producers.

Fixed connection charges are assumed to recover part or full amount of costs of individual connection facility (connection line, electricity meter, metering cabinet etc.). In addition, variable connection charges are applied to ensure network user's contribution to overall network development costs, thus reflecting capacity driven structure of these costs.

The share of network development costs to be recovered through connection charges should not be over excessive on the one side, but should not be unreasonably low on the other side. Over excessive charge would pose unreasonable upfront burden for new network users, having in mind that network infrastructure is also used by existing users. Likely discrimination of new network users may appear under conditions when they are required to pay variable unit costs higher than marginal costs of network capacity to serve one unit of additional load.

Unreasonable low level of variable capacity driven connection charge, in combination with volumetric (consumption-only based) use-of-network tariffs, may lead consumers to request higher contracted capacity than what is really needed, thereby providing deceptive signals to the DSOs about the necessary network capacity to host new connection. In addition, low level of variable connection charges might be to the detriment of the DSOs cost efficiency, as DSO investments in network capacity are based on the customers' peak demand. Therefore, the risk of assets stranding is likely to occur under those conditions.

Consumer's connection fee may be determined on a case-by-case basis or alternatively may be standardized for specific consumer's class. Main disadvantages of case-by-case determination are less predictability, free riding and possible over excessive connection costs for consumers in remote areas. On the other side, standardized connection charges might be appropriate solution to address fairness principle, as the consumers would pay same connection charges regardless on the distance between the consumer's location and the existing distribution network. It also takes account of the social cohesion principle stipulated in Directive 2008/72, Art. 3(4).

Alternative option to address fairness issue is to set uniform unit prices per kW of contracted capacity, which covers both the costs of individual connection facilities and the share of network development costs. This solution is easy to implement, but is less transparent and less fair in comparison with the combined fixed and variable connection charges.

A vast majority of new connections is constructed for low voltage consumers and it is preferable from a technical and commercial perspective, to standardize connection types and fees applied depending on the line type (overhead, underground) and the contracted capacity. Standardization of connection types facilitates connection tariffs calculation and implementation, thereby improving overall process transparency. Remaining connections of medium voltage consumers and power producers may be treated as the non-standard connections to be charged on a case-by-case basis, since the number of those connections per year is relatively low. End users who had paid actual costs of connection should be reimbursed if the installed facilities are later used to connect new network users.

In some cases consumers may request higher level of security of supply than it is provided by the DSO's standard connection service and DSO's General terms and conditions. For example, consumer may request power delivery to be provided using ''n-1'' security criteria at the connection level, thus requesting additional connection facility to be constructed. Under such conditions, consumer should be charged for the full costs of connection facilities, regardless on the connection charging regime. Unlike the electricity consumers, generators are less likely to opt for higher level of security at the connection level. This could be explained by the fact that the cost of losing connection for generation is significantly less than for demand (the unit cost of not generating equals the electricity price at that point in time increased by imbalance costs, while value of lost load may be generally many times higher).

Regulatory framework should not permit under any conditions that single network user is charged for the full costs of upgrading existing network that is needed to accommodate the network user's demand/production, thus avoiding occurrence of ''free riding problem''. Such situation is likely to occur under conditions when existing transformer or distribution line have already reached its thermal capacity and connection of new network user triggers the need to upgrade its capacity or to construct new facilities to which network users shall be connected. Similarly, if a new power plant is to be connected in the area with already high level of short circuit current, switchgear replacement may be needed because of the additional short circuit current contribution that summed up with existing level exceeds switchgear's rated capacity. In both examples, it is against the fairness principle to charge new network user for the full costs of network facilities upgrade. Therefore, it is recommended that new network user may only be charged for a fraction of existing network upgrade costs, in proportion to the ratio of its installed capacity and capacity of upgraded network facility. The remaining costs are to be socialized and paid by existing network users through use-of-network tariffs.

Currently, 8 out of 24 EU Member States apply deep charging regime, 7 apply shallow, while 9 countries apply combination of these methods[65].

Deep connection charging regime is considered to be an optimal method, particularly having in mind that shallow charging regime may provide deceptive capacity signals to the DSO regarding the network development needs. Furthermore, deep connection charging regime had been applied in EnC CPs historically and fair treatment of new and existing network users may be assured by the reasonable trade-off between deep connection tariffs and use-of-network tariffs.

***Deep connection charging method is commonly applied as a safeguard to minimize stranded costs of unused network facilities in the same time providing fair charging to connecting users with view to marginal costs they cause to the distribution network.***

## 6.5 CLASSIFICATION OF COSTS COMPONENTS AND TARIFF DESIGN

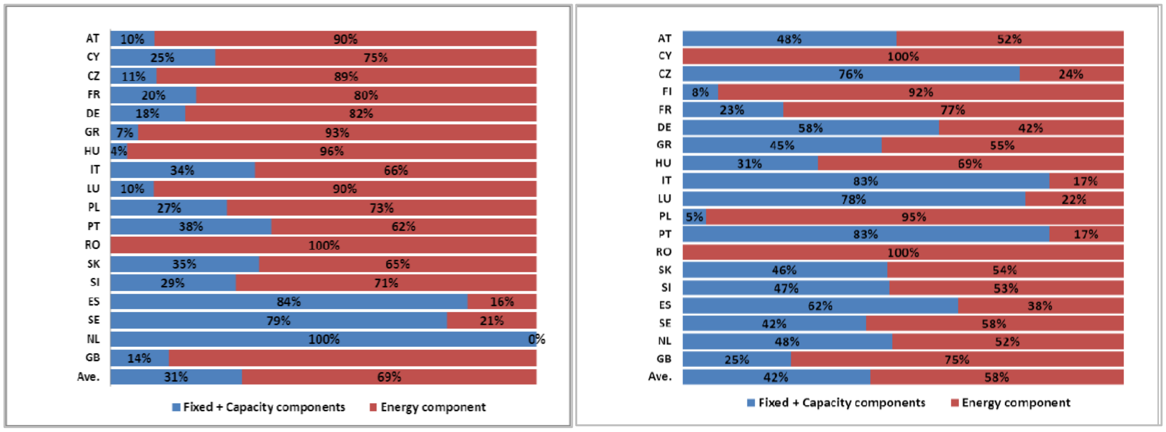
### 6.5.1 Distribution system cost reflectivity

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, those costs are fixed irrespective of the quantity of distributed electricity. Minority of costs are variable costs usually based only on the distribution grid losses. However, current distribution tariff structure does not explicitly allocate fixed and variable cost to corresponding fixed and variable network charges in majority of European countries.

The tariff component weight in consumers' grid costs is the most important indicator for the quantitative analyses to be performed to reveal the level of cost reflectivity in distribution tariffs.

[65] EC DG ENER Dir B, Study on tariff design for distribution systems

The average active energy and capacity components weights in total grid costs for household and large industrial consumers in EU Member States in 2015 are shown in Figure 18[66].



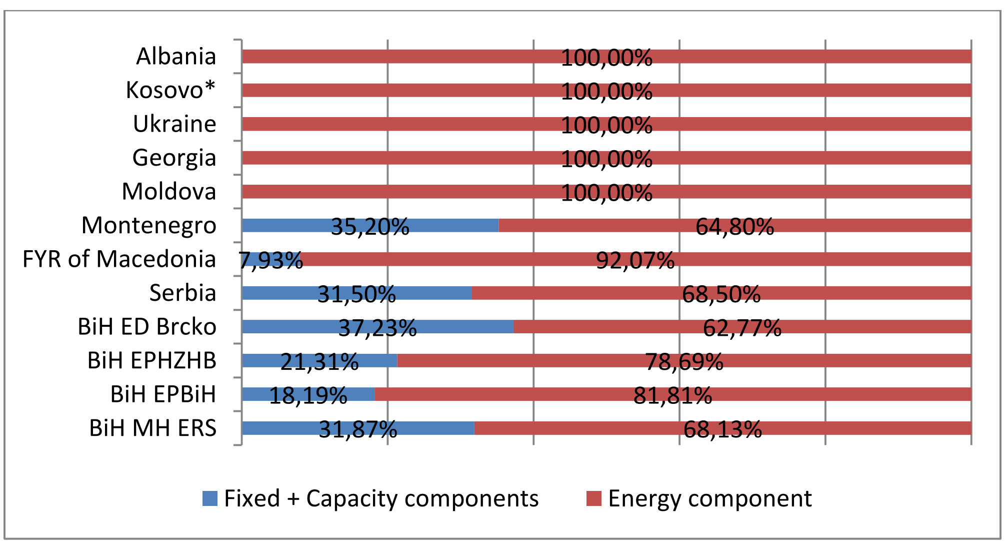

*Source: European Commission, Directorate General for Energy*

**Figure 18** *Distribution tariff component weight in Households and Large Industrial consumers*

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 only a few countries including Spain and Sweden the fixed or capacity component is dominant, around or above 80%, while in the Netherlands the totality of costs is charged through the capacity component for household consumers.

The average active energy and capacity components weights in total distribution grid costs at the power system level in the EnC CPs are shown in Figure 19.




*Source: EnC Secretariat / ECDSO-E Network Tariff Task Force*

**Figure 19** *Distribution Tariff component weight in the Energy Community*

[66] EC DG ENER Dir B, Study on tariff design for distribution systems, p. 114

As shown in Figure 19, similar relative share between tariff components is observed in the EnC CPs when compared with the EU countries, with the vast majority of DSOs having fixed and capacity components share under 35%.

On the other side, average share of fixed costs in the DSOs total regulatory approved revenues in the EnC CPs is around 80%, depending on the level and the price of recognized losses.

***True cost reflectivity of distribution tariffs can only by achieved by gradual increase of capacity tariffs weight in total grid costs. This task is not easy to implement and it may require relatively long transition period with gradual changes before reaching its target weight of different tariff components. The task is also dependent on the smart metering roll-out as the issue of fairness may be opened if only the consumers with the smart meter are switched to the new tariff structure.***

### 6.5.2 Allocation of costs and rate design

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

The non-discrimination and competitiveness of network users is strongly dependent upon the network pricing arrangements. Regulation theory allows that end user tariffs may be calculated either by DSO itself or by the regulators as a part of the revenue approval process. Which solution is to be applied depends on the specific regulatory framework.

Total DSO's costs are to be apportioned on consumer's classes depending on the following data for each class:

- Number of consumers,
- Quantities of electricity consumed,
- Quantities of peak demand (annual sum of monthly values),
- Contribution of consumer class to system peak demand.

DSO should be obligated to allocate all business costs to the corresponding voltage levels to the extent feasible. Non-allocated costs should also be allocated for each voltage level using predefined allocation methods.

DSO's total costs should be classified as demand-related, energy-related and consumer-related per each voltage level in order to make cost reflective allocation. Costs allocated to lower voltage levels should be calculated as the cumulative costs, which include the costs of higher voltage levels that are used for electricity delivery.

For large industrial and commercial consumers peak demand to be charged is consumer's measured individual peak demand, non-coincident to system peak demand, where the contribution to overall system peak demand is incorporated through the coincidence factors at the class level.

For households and small commercial consumers demand charge is usually based either on the contracted individual capacity or on the average employed capacity within the class, unless the smart metering roll out is completed and metering infrastructure allows individual peak demand to be measured. Whichever method is applied, contribution of individual consumer and consumer's class to the system peak demand should be reflected through the relevant coincidence factors.

Key regulatory challenge regarding the cost allocation is to set an optimal share of fixed costs to be recovered through the demand charges, which improve the fairness and equity in cost recovery as they reflect 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 in order to reduce maximum demand from electricity network. It also raises applicability concerns, as the price signals of cost reflective tariffs may not be understandable to small consumers and those consumers without proper metering system. In addition, cost reflectivity may be distorted without correct data, particularly in dynamic changing environment.

Based on the previous theoretical considerations it would be cost reflective to allocate full amount of DSO's fixed costs to demand – driven charges based on long term marginal cost and taking into account opportunity costs, both difficult to determine in the distribution network. However, optimal balance of demand charges vs. fixed costs should be carefully considered and addressed when designing a new pricing model, also recognizing and taking into account a whole range of issues related to broader energy, environmental and social policy goals such as:

- Well functioning electricity market,
- Energy efficiency,
- DG integration,
- Demand response,
- Heating fuel parity,
- Protection of vulnerable consumers and affordability,
- Effects on lower usage consumers and fairness.

The expansion of energy-efficiency programs and distributed generation, coupled with the recent economical crisis has led to the significant decrease of the delivered electricity with the direct impact on the DSO's revenue reduction. On the contrary, costs for network operators are not reduced as a result of decreased consumption.

Various DER technologies are in some literature also called ''disruptive forces'' with regard to the electricity distribution activity, because of the effect they produce on the DSO revenue through the consumption reduction.

Table 4 provides the electricity consumption reduction statistics for some EU Member States and Norway in 2014 compared to the 2011[67].

[67] EURELECTRIC Position Paper, Network Tariffs, p. 5

**Table 4.** *Electricity consumption in period 2011-2014*

| Country | Total distributed energy (TWh) in 2011 | Total distributed energy (TWh) in 2014 | Decrease (%) |
|---|---|---|---|
| Cyprus | 4,6 | 3,9 | 15,2 |
| Spain | 278 | 259 | 6,8 |
| Germany | 510,6 | 495,9 | 2,9 |
| Denmark | 32 | 30,6 | 4,4 |
| Finland | 60 | 59 (2013) | 1,7 |
| France | 363 | 362 | 0,3 |
| Greece | 45,7 | 42,6 | 6,8 |
| Italy | 287 | 262,4 | 8,6 |
| Norway | 118 | 115 (2013) | 2,5 |
| Portugal | 47 | 44 | 6,4 |

Table 5 provides the gross electricity consumption data for EnC CPs in the period 2013-2016.

**Table 5.** *Electricity consumption in EnC CPs in period 2013-2016*

| Country | Gross consumption (GWh) | | | | Decrease |
|---|---|---|---|---|---|
| | 2013 | 2014 | 2015 | 2016 | 2016-2013 |
| Albania | 7.986 | 7.815 | 7.287 | 7.093 | -11,18% |
| Bosnia and | 12.559 | 12.210 | 12.606 | 12.865 | 2,44% |
| Kosovo* | 5.519 | 5.399 | 5.570 | 5.342 | -3,21% |
| FYR of Macedonia | 8.138 | 8.026 | 7.887 | 7.461 | -8,32% |
| Moldova | 4.079 | 4.130 | 4.153 | 4.101 | 0,54% |
| Montenegro | 3.323 | 3.290 | 3.464 | 3.338 | 0,45% |
| Serbia | 35.007 | 34.130 | 34.115 | 34.018 | -2,83% |
| Ukraine* | 165.487 | 157.922 | 136.262 | 133.513 | - |
| **Energy Community** | **242.098** | **232.922** | **211.344** | **207.732** | **-** |

** Ukraine 2015 – 2016 without Crimea*

*Source:* EnC Secretariat

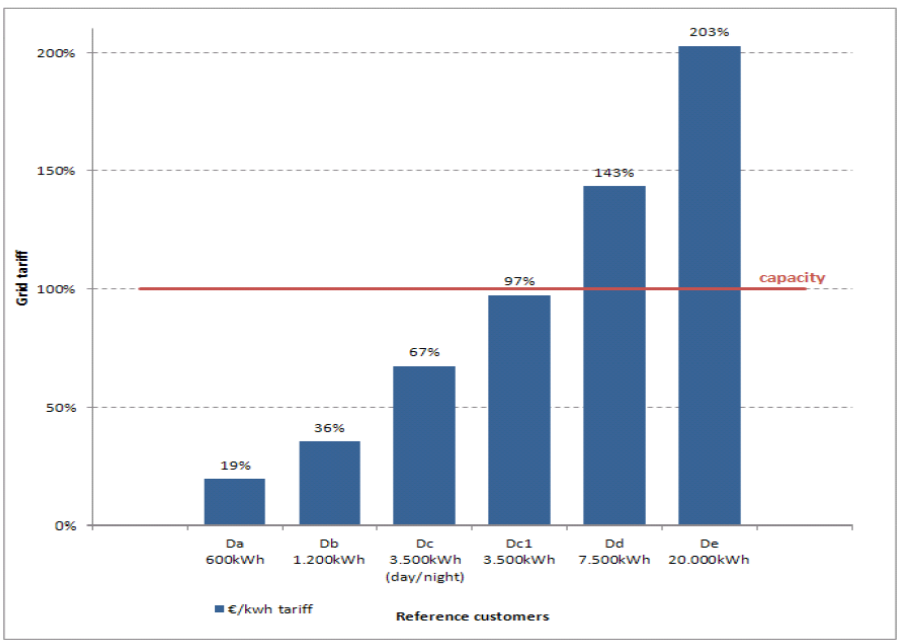
Dominantly volumetric use-of-network tariffs have a significant impact on the DSO's profitability, since a very small percent of consumption deviation has a strong impact on the achievable rate of return.

An exposure to the non-controllable volume and revenue risks, as a consequence of DGs installation for self-consumption purposes and energy efficiency measures, raised concerns about decreased DSO's revenues and tempted regulators to provide alternative solution to assure DSO cost recovery. Some authors' concerns are dramatic, with the apprehension that this situation may lead to a vicious circle of decreased consumption - lost revenues – rate increase – customer reaction – DER and energy efficiency accelerated deployment - decreased consumption; unless the tariff structure is redesigned. A vicious circle effect may be additionally aggravated as the increased uncertainty and risk will cause investors to request higher rate of return with erosion of credit rating. The decline in credit rating may further lead to higher cost of debt, directly increasing consumer's rates and accelerating deployment of DER and energy efficiency programs.

Taking into account the cost structure of the distribution companies with the dominant share of fixed costs, higher demand charges are likely to be a proper solution to address DSO costs recovery and volume risk, providing more stable distribution revenues. However, a transition to higher demand charges is not an easy task for regulatory authorities as it entails deep analyses in much wider context than it is the cost reflectivity and cost recovery.

Higher demand charges are expected to sharply increase costs of electricity for low use consumers, while a proportionally decreased unit costs charged per kWh can undermine efforts and incentives to decrease consumption through the energy efficiency programs. High demand charges with relatively low variable charges may even lead to unnecessary increase in consumption, particularly for heating purposes as a consequence of fuel parity imbalance. The consumers may decide to change heating fuel and to replace other fuel types with cheaper electricity with low volumetric rates. The analyses provided by Regulatory Assistance Program (RAP), shows that full cost reflective capacity and volumetric tariffs may increase overall consumption by 14,5% as a result of moderate demand elasticity of -0.2 (a 1% decrease in price results in a 0.2% increase in usage)[68].

Figure 20 shows the possible impact of the introduction of the full cost reflective capacity tariffs for several reference consumers defined by EUROSTAT[69].




*Source: CEDEC*

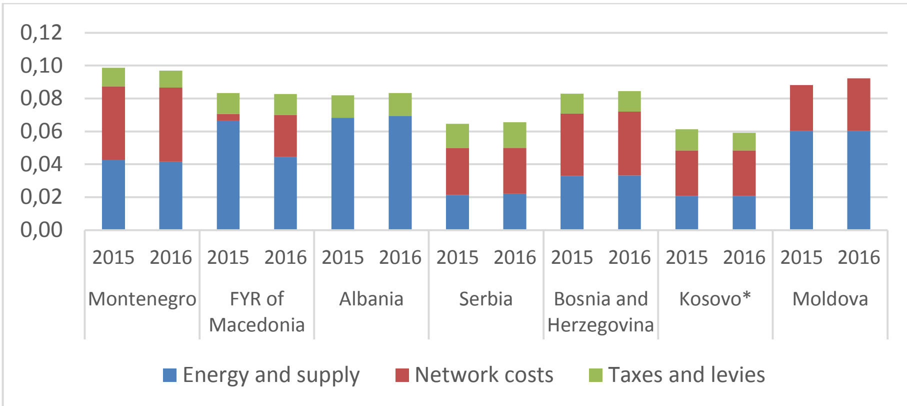
**Figure 20** *Impact of the introduction of capacity tariffs for reference customers*

68 RAP Smart Rate Design For a Smart Future, Appendix D, p. D-3

69 CEDEC Position Paper, Distribution Grid Tariff Structures for Smart Grids and Smart Markets, p. 7

The red line reflects single capacity tariff, while the blue bar reflects the volume based (kWh) network tariff as a percentage of the single capacity tariff. As it can be seen, grid charges for reference consumers in Da and Db consumption bands would be 3-5 times higher if pure capacity based tariffs are applied.

Figure 21 shows the breakdown of retail electricity prices into the components[70] (in €c/kWh). Data for Albania in 2015 and 2016 and for FYR of Macedonia in 2015 are not comparable as the network charges were not disclosed accurately.




*Source: EnC Secretariat based on EUROSTAT publication*

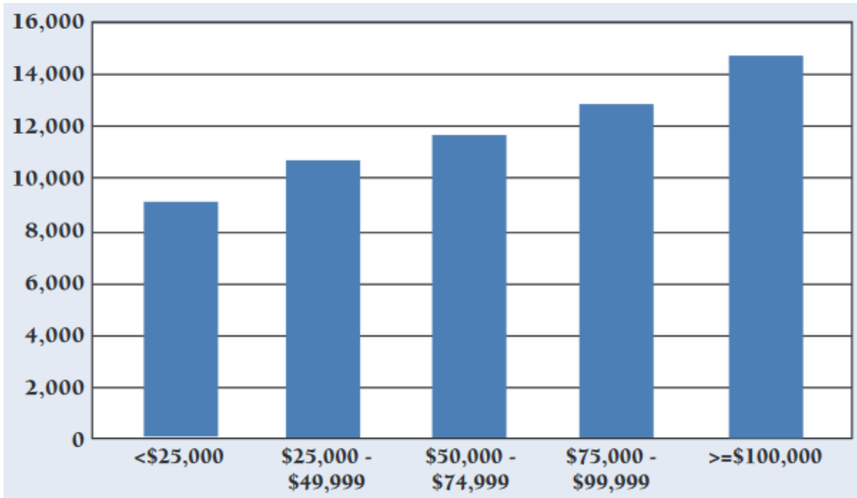
**Figure 21** *Breakdown of electricity prices charged to medium households*

Share of network costs in household's total electricity expenses in some EnC CPs is even higher than energy costs share. Changes of network tariffs design directly influence the structure of retail electricity prices, thus also impacting consumer's behavior and consumption level as a result of demand elasticity.

Low income vulnerable consumers are expected to face increase in their bills as they are typically, but not necessarily low use consumers. Figure 22 shows the annual consumption per household per income strata in USA for 2014[71].

[70] EnC ECDSO-E Task Force, Distribution Network Tariffs Costs & Tariffs Design

[71] RAP Smart Rate Design For a Smart Future, p. 48




*Source: RAP*

**Figure 22** *Annual kWh use per household by income strata in USA*

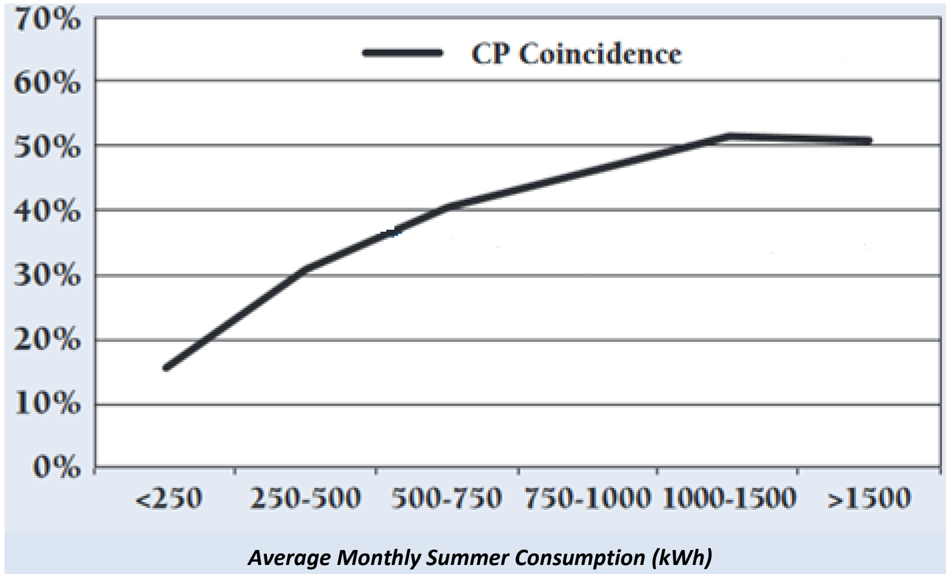
Dedicated study on the correlation between annual consumption and household's income would be necessary to provide comparable data in the respective EnC CPS and to properly asses the impact of tariff design and tariff rates on the vulnerable electricity consumers.

Higher demand charges impact on low income consumers may aggravate the energy affordability, having in mind current levels of households' income. For a comparison, according to European Commission survey conducted during the 2014-2015, between 17%-20% of electricity consumers in Slovenia, Hungary, Romania and Croatia reported that sometimes or even often can not pay their electricity bills on time[72]. Those percentages are very different from the data reported by well developed countries such as Austria, Germany, Norway, Sweden and Netherland, where it accounts for less than 5%.

European household's share of income spent on energy has been increased to the level of about 6% for average households and 9% for the poorest households in 2014[73].

Figure 23 shows that low use household consumers have lower contribution to the system coincident peak (CP), calculated as the ratio of simultaneous maximum demand of a group of consumers coincident to the power system peak demand to the sum of their individual maximum demands[74].

[72] EURELECTRIC, Position paper, Energy Poverty, p. 2
[73] EURELECTRIC, Position paper, Energy Poverty, p. 7
[74] RAP Smart Rate Design For a Smart Future, p. 51




Source: RAP

**Figure 23** *Usage levels and consumers coincident summer peak demand*

Demand charges applied in a typical way treat the customer who uses capacity for only a few hours (such as the churches, elevators, draining pumps, sport stadiums, holiday homes etc.) exactly the same as a customer using relatively the same level of capacity at all hours (such as the 24-hour shops). A question whether the consumer who uses the capacity longer should pay more for the use of that capacity can be raised from the aspects of fairness and possible cross subsidization.

If distributed storage technologies become more affordable in combination with PV installation, as it is expected in the near future, higher fixed charges may even lead those prosumers to disconnect their installations from the grid permanently. Such a situation is undesirable from the DSO's perspective too, not only because of the revenue reduction, but also as the source of flexibility should be lost from the power system. The rate design should not encourage prosumers with storage systems to disconnect and operate as the small isolated islands, thus endangering own security of supply but also depriving DSO of DER resources.

When considering redesign of tariff structure, it is important not to overlook that household and small commercial consumers who generally use modest amounts of energy, prefer to have electricity bills as simple as possible. Introducing the complex tariff structures with possibilities of active demand side management and some form of dynamic pricing may face indifference and low level of participation when offered to those consumer's classes.

It is worth to emphasize that there are some authors arguing that monthly fixed charges should only reflect consumer's specific costs, while the remaining dominant part of fixed and variable costs are to be recovered through ToU volumetric tariffs. A problem is particularly relevant for households and small commercial customers because *''a customer's highest hourly usage may be a poor predictor of their monthly or annual usage, or of the demand they place on the grid during peak hours and therefore the* *costs incurred to serve them''*[75]. Key argument provided is that regulation should prevent the exercise of monopoly power. RAP in its document Smart Rate Design for a Smart Future[76] gives a challenging thesis, stating that: *''the imposition of a fixed charge for the privilege of being a customer is almost non-existent in the competitive world. Oil refineries, hotels, airlines, and supermarkets have significant fixed costs, including building and equipment. Even their labor costs do not vary directly with sales volumes. But all of these recover all their fixed and variable costs through volumetric prices. In a competitive environment, it is essentially impossible to charge a customer for the privilege of being a customer. In fact, we find quite the opposite — special discounts offered to attract new customers, to try to build a business relationship that will then continue over time.''* It is further stated that allowing a utility to impose high fixed monthly charges would be exercise of monopoly power. Instead of applying higher demand charges, this paper foresees time-varying energy charge to address cost-reflectivity of distribution tariffs.

A shift to demand charging of household consumers brings new concerns about impacts on low income and low consumption customers. Vulnerable customer groups that are assumed to have low electricity consumption would be exposed to increased costs of service, in comparison with the tariff design based on the volumetric rates that incorporate majority of distribution service costs.

At the end of analysis it is important to stress that DSOs will inevitably incur the increased costs when introducing the new tariff structure as a result of metering infrastructure and billing software upgrade, database adjustment etc.

***Having in mind how contrarian arguments for tariff design are, the optimal rate design represents a great challenge for regulators, who are required to provide reasonable compromise and balance among conflicting objectives and opposite interests of numerous stakeholders. Distributional impact analyses might be needed to assess possible effects on different consumer's classes, but also to confirm compliance with other policy goals.***

### 6.5.3 Time-of-Use tariffs

Time-of-Use network tariffs are used to charge different prices at pre-defined periods of the day or year. They are used as a complementary tool to support efficient use of the network, to reduce peak demand, to shift consumption to off-peak period, to enhance flexibility and demand side response etc.

ToU tariffs are generally defined for the ''peak'' and ''off-peak'' periods (day/night) with/without seasonal variation (low/high season), based on the functionalities of conventional electricity meters. Smart meters provide enhanced functionality with possibility to pre-define more pricing periods such as critical peak pricing etc. ToU tariffs can be volumetric, capacity based or a combination of both.

***ToU volumetric tariffs should be applied as a default pricing option provided that consumer's metering infrastructure enables application of time based tariffs, thus providing pricing signal for efficient use of network, peak demand reduction and demand side response in general.***

[75] RAP, Smart Rate Design for a Smart Future
[76] RAP, Smart Rate Design for a Smart Future

### 6.5.4 Geographical uniformity

Geographical variation in the DSOs' network tariffs is important element of tariff design as it impacts the principle of equity/fairness. Geographical conditions, network density, share of underground cables, average consumption per metering point are some of the factors which directly influence the level of average distribution tariffs.

From the equity/fairness position, it is preferable to have geographically uniform network tariffs, but in some cases this aim is not achievable due to large number of DSOs under regulatory jurisdiction. A task is easy to implement in situation when a few DSOs are concerned, particularly if they are owned by the same shareholders.

If geographically uniform network tariffs are applied, specific mechanism for inter DSOs compensation has to be established to settle the difference resulted from application of uniform tariffs instead of DSO's specific tariffs.

Currently, 10 out of 24 EU Member States apply geographically uniform network tariffs[77], like a Spain, France, Italy etc. On the other side, non-uniform tariffs are applied in Austria, Germany, Denmark, Great Britain, Norway, Sweden etc. In some of those countries, like Germany, Denmark or Sweden, number of DSOs is extremely high and inter DSOs compensation would hardly be administratively feasible.

Specific solution is applied in Norway, where an annual grant through the government budget is provided to reduce the distribution tariffs in the areas with highest costs per kWh distributed. The grant is transferred to the companies with higher costs, thereby protecting consumers from the over excessive DSO tariffs. In Sweden, DSOs operating in neighboring areas are allowed to engage in joint accounting to apply same network tariffs in the joint area.

***Whenever feasible, geographically uniform tariffs should be determined as a legitimate tool to ensure the equality of access to power system to the customers and the interest of social cohesion too, particularly when depopulation of rural areas poses a problem to the community.***

## 6.6 ELECTRICITY TARIFFS FOR PRODUCERS – G CHARGES

General considerations with regard to the tariff components and allocation of network development costs, as given in sections 6.3 and 6.4, are applicable to electricity producers too. Producers are generally charged for network services through the upfront one time connection fee, however the network use services may also be charged, depending on the specific regulatory framework.

A term ''G charges'' is used to reflect the values of transmission or distribution charges faced by producers for the network use services.

The following types of G-charges may be applied[78]:

- Energy-based G-charges are charges payable on every unit of energy produced and/or injected into the grid (€/MWh),

[77] EC DG ENER Dir B, Study on tariff design for distribution systems
[78] ACER, Opinion of the Agency on the Appropriate Range of Transmission Charges Paid by Electricity Producers, p. 2

- Capacity-based G-charges are charges payable on the capacity connected to the grid, on yearly or multi-year peak output or output under peak conditions (€/MW),
- Lump-sum G-charges are charges that are fixed at the start of the relevant charging period and do not depend on capacity connected, on yearly or multiyear peak output or on output under peak conditions, unless these are taken into account in the form of an average over a past period of at least 5 years.

For accurate analyses and comparison of different tariffs for producers, it is important to provide the definition of G-charges, as given by EU Regulation No 838/2010[79], end to emphasize that G-charges do not include:

- Charges for physical assets required for connection to the system or the upgrade of the connection,
- Charges paid by producers related to ancillary services,
- Specific system loss charges paid by producers.

In its opinion Agency for Cooperation of Energy Regulators (ACER) states that Regulation No 838/2010 only harmonizes G-charges at the transmission level and that it should be carefully considered if and how this Regulation should be amended to harmonize charges for generators connected to distribution grids. ACER emphasizes that the effects of different levels of charges are in principle transferable to G-charges related to the distribution level, but also observes that generators connected to the distribution grids, as well as the distribution grids themselves, may have different characteristics that would have to be considered.

### 6.6.1 G-charges at the transmission level

In its opinion ACER recognized that there is an increasing risk that different levels of G charges could distort competition and investment decision, unless the G-charges are cost-reflective, applied appropriately and efficiently and, to the extent possible, in a harmonised way across Europe.

Agency considers that:

- Energy-based G-charges (€/MWh) shall not be used to recover infrastructure costs; and, therefore, except for recovering the costs of system losses and the costs related to ancillary services, where cost-reflective energy-based G-charges could provide efficient signals, energy-based G-charges should be set equal to 0 €/MWh.
- Different levels of power-based G-charges (€/MW) or of lump-sum G-charges, as long as they reflect the costs of providing transmission infrastructure services to generators, can be used to give appropriate and harmonised locational signals for efficient investments in generation, e.g. to promote locations close to load centers or where the existing grid can accommodate the additional generation capacity with no or minimal additional investments.
- It is unnecessary to propose restrictions on cost reflective power-based G-charges and on lump-sum G-charges.

[79] Regulation No 838/2010, Annex Part B

The Agency notes that even power-based G-charges may have significant distortive effects on investment decisions if they are not cost-reflective, lack proper justification or are not set in an appropriate and harmonized way.

In total, 10 out of 28 EU countries (including Norway) apply G-charges. The annual average G-charges were in the range 0,19 to 1,96 €/MWh in 2012. The highest level was recorded in Romania, followed by Ireland and North Ireland with the 1,77 €/MWh. In Romania producers paid 41% of the total TSO revenue in 2012, while in Sweden this share was 32%.

G-charges variations are mostly driven by the generator's location, followed by the voltage level at the connection point. Locational signal can be provided either in the form of nodal short term marginal costs of transmission or through arithmetical location dependent formula.

Out of six countries that apply locational transmission tariffs, three of them (Finland, Norway, Spain) charge the shallow connection costs, Denmark do not charge connection costs at all, while Romania and Sweden charge the deep connection costs.

As deep connection costs are also considered to provide locational signals, one may conclude that Romania and Sweden apply dual locational signals as the input in setting transmission connection and usage tariffs.

Austria, Romania and Sweden charge producers for the losses in transmission system, while the costs of ancillary services are charged in Austria, Belgium and Great Britain.

### 6.6.2 G-charges at the distribution level

All the above mentioned principles may be applied for power plants that are connected at the distribution level, as the cost structure of transmission and distribution grids is very similar.

Making a general assessment about the impact of DGs on distribution networks is a very complex issue. Presence of DGs in distribution network affects a number of fields such as voltage regulation, thermal loading, losses, network security, balancing and imbalance settlement, reduction/increase of investment etc. The DG impact is site specific, variable in time, depends on the availability of the primary resources, size and operational regime of the plant, vicinity of the load, layout and electrical characteristics of the local network, etc. It is therefore very difficult to express cost impact of DG's on distribution network by relatively simplistic tariff structure if being applied.

Currently only four EU Member States apply G-charges at the distribution level: Spain, Ireland, Slovakia and United Kingdom[80]. The G-charge level in Spain is 0,5 €/MWh, while Ireland charges generators for O&M costs related to the connection asset and facilities added for reinforcement. Slovakia applies decreased capacity charge for embedded generation at the level of 30% of standard unit price, while UK applies somewhat different G-charge structure as the tariff may be both positive and negative, depending upon plant's impact on the distribution system.

Remaining vast majority of EU Member States do not charge distributed generation for network usage services. Similar practice is present in EnC CPs, as none of the CPs applies G-charges at the distribution level at the moment.

[80] EC DG ENER Dir B, Study on tariff design for distribution systems

In Germany there is no G-component, but DGs receive an avoided cost allowance related to costs of upper voltage levels.

In general, the presence of DG changes the power flows and therefore the losses incurred in distribution network. If the level of penetration is low, DGs would normally, but not necessarily, contribute to power loss reduction because of the netting of power flow. On the other hand, higher levels of penetration may cause increased network losses. The impact of a DG on the network losses may be assessed by calculating the difference in losses when the power plant is connected and when it is disconnected from the network. In that sense, regulator may decide to recognize the impact that DGs have on network losses by setting premium/charge to be received/paid by a DG operator, depending on the effect it generates.

### 6.6.3 G-charges impact on electricity market

Main reasoning for introduction of G-charges is given by the fact that both generators and electricity consumers use the electricity network and thereby they are supposed to share the costs of services. Additional reason is that tariff structure should be used to incentivize investment in generation at the locations that are in the vicinity of existing grid and loads.

On the contrary, main disadvantages of the G-charges application are the effects on the efficient power plants dispatching, market prices and investment decisions. The situation is even more aggravated if the G-charges are not applied uniformly, as it is the current state.

If energy based non-uniform G-charges are applied, a double negative effect is observed at the electricity market. Firstly, it may happen that production from cheaper power plants facing relatively high G-charge levels is replaced by less efficient plants facing relatively low G-charge levels. Additionally, a final effect of the energy based G-charges is reflected through the spot market price increase as it increases according to the level of G-charges charged to the price-setting power plants.

Secondly, investment decisions are influenced by the different levels of G-charges, as the additional costs may deteriorate the investment signals. However, a decision where to invest primarily depends on the resource availability, environmental conditions, planning documents and permissions, space availability etc.

Similar effect of spot market price increase can be expected if the capacity based G-charges are applied in markets with low competition, as the generators are likely to increase the price they offer at the market in order to reimburse additional grid costs. Theoretically, at the well developed markets with high level of competition at the wholesale side, capacity based G-charges may not influence dispatch and pricing decision.

European Wind Energy Association (EWEA) has recently published its position paper related to the network tariffs and grid connection regimes[81], pointing out that diverging network charges across EU Member States lead to investment distortions and hold back efficient deployment of wind energy in Europe. EWEA provided an exhaustive list of messages implicitly or explicitly addressed to the ACER, urging the ACER to draft Framework Guidelines for a Network Code on harmonized transmission tariff structures as soon as possible.

[81] EWEA Position paper on network tariffs and grid connection regimes

Main messages provided in this Paper are:

- The structure of network tariffs and connection regimes are highly interdependent and must be evaluated and harmonized in a combined effort.
- Distortive and non-harmonized tariffs will increase the system's long-term costs, which is ultimately borne by the system's customers.
- G-charges should be harmonized as soon as possible, and removed in the long term to ensure that future investment decisions are driven by resource availability. These costs should, therefore, be socialized, as recognized by ACER.
- Locational and power based G-charges tend to penalize wind power plants. Therefore, G-charges should be energy-based and should abstain from a general inclusion of locational signals. Locational signals should instead be provided by efficient congestion management.
- New generating capacity should not be charged the full cost of overall grid reinforcements emerging from their marginal contribution to the power system in comparison to older, exempted, power plants. Therefore, shallow grid connection charging regimes, both at transmission and distribution level, should be best practice across Europe, notably in Member States where powerbase G charges and disproportionate locational signals apply in parallel.

Based on the analyses of locational tariffs applied in Europe, EWEA concludes that locational signals tend to discriminate wind power generation since the choice of location when making an investment decision is driven by availability of resource rather than vicinity to load centers. EWEA recognizes additional discrimination of wind power generation by imposing the grid reinforcement costs to the new power plants alone and by applying the capacity based G-charges on the power plants with lower running hours.

EWEA highlighted a very important and critical issue of connection charges design, stating that it is not possible to identify one (new) point of generation as the single cause of grid congestions and resulting needs for reinforcing the grid, other than it being ‘’the straw that broke the camel’s back’’.

Same topic was a subject of interest of EURELECTRIC too, who published its position paper[82], suggesting following principles to be applied for transmission tariffs paid by generation plants (G charges):

- The structure and value of G-charges should be harmonized throughout Europe to avoid price, dispatching and investment distortions;
- The existing caps on the level of G-charges should be maintained as an interim insurance against market distortion;
- To guarantee maximum harmonization and minimize distortions in generators’ investment and dispatching decisions, all systems should gradually move towards a G charge as close to zero as possible;
- In particular, to minimize distortions on generators’ behavior, the power-based charges (€/MW) applied to generators should be set to zero as fast as possible;

[82] EURELECTRIC, Harmonization of electricity generation transmission tariffs

- The cost of losses or ancillary services constitutes an obstacle for tariff harmonization and these elements should therefore be removed from transmission tariffs and be charged separately.

EURELECTRIC emphasizes that the harmonization of transmission tariffs and their methodologies is a third necessary element for a successful development of a European electricity market. In that sense EURELECTRIC advocates a harmonization in both the structure of transmission network tariffs and the costs they cover to avoid distortions in both the long-term investment market and the short term dispatch market. According to the EURELECTRIC positions, all systems should gradually move towards a level of transmission charges applied to generators as close to zero as possible. Key argument against the introduction of capacity charges for generators is a counter-productive effect if the same time-differentiated power-based charges (€/MW) is applied for generation and load to discourage network usage in peak hours. Reduced consumption in peak hours stabilizes the network but reduced generation in peak hours has the opposite effect.

### 6.6.4 Reactive energy treatment

Power plants might consume reactive energy during the normal operation regime and the issue whether power producers should be charged for this cost need to be addressed by regulatory authority. Consumption of reactive energy is a result of asynchronous generators installation, power plant adjustment to network voltage variations or Volt-Var regulation in the distribution network. Generally speaking, reactive energy consumed by power plants while generators are in operation mainly depends on the network voltage variations which are out of control of power plant operator.

Consumption of the reactive energy by power producers may be treated as:

- Equivalent to the consumption by electricity consumers,
- A part of network services provided by network operator,
- The services provided by power producer to the DSO, if reactive energy is consumed based on explicit requirement from DSO as a part of voltage regulation related activities.

Under first option, power producer has to bear costs of consumed reactive energy, provided that relevant tariff is prescribed by the tariff design. Under second option, reactive energy that is delivered to power plants is treated as a part of network use services, therefore power producers should not be charged any costs related to reactive energy consumption provided that they are generally exempted from G-charges payment. Under third option, regulator may set a tariff to be paid by DSO as remuneration to power producer for the voltage regulation services.

Reactive energy is usually consumed as a result of power plant operating regime adjustment to increased voltage conditions in distribution network, with the aim to keep voltage magnitude in DG facilities within the permitted tolerances. Under these conditions, operating regime is adjusted by power plant operator as a forced measure to avoid power curtailment and insulation stresses due to impermissible over voltages.

## 6.7 POSITIONS - COSTS ALLOCATION AND DESIGN OF NETWORK TARIFFS

| | |
|---|---|
| GENERAL<br>REGULATION MODEL AND REGULATORY PERIOD | Optimal price regulation model is considered to be a coherent mix of the most appropriate regulation methods applied for specific category of costs:<br>• Capital costs are regulated using the rate of return (cost plus) regulation method.<br>• Controllable operating costs are regulated using the revenue-cap regulation method with efficiency incentives. Yardstick regulation method is the most common method applied to set utility's efficiency targets.<br>• Non-controllable operating costs are not subject of incentive regulation and they are simply passed through to the consumers.<br>• Costs of distribution losses are set on the basis of DSO's past performance with the individually set incentive targets.<br>• Quality of supply bonus/malus is set by applying the performance-based regulation method<br>Network innovation should be regulated separately by applying specific ad-hoc regulatory schemes.<br>The length of the regulatory period should be sufficient to allow the regulated utility to reach the imposed efficiency targets and thereby to reap benefits until the next price setting period. Reasonable length is assumed to be in the range 4-5 years. |
| 6.4<br>ALLOCATION OF NETWORK DEVELOPMENT COSTS, TERMS AND CONDITIONS FOR CONNECTION | Use-of-network tariffs and connection tariffs should be addressed together, as the level of connection tariffs directly influences DSO revenue that is recovered through the use-of-network tariffs.<br>The share of network development costs to be recovered through connection charges should be reasonable; over excessive and unreasonably low charges should be avoided.<br>Consumers' contribution to the overall network development costs should be provided through the variable connection charges, depending on the contracted capacity.<br>New network user may be charged only for a fraction of existing network upgrade costs, in proportion to its marginal contribution to the capacity of upgraded network facility.<br>Connection charges related to the individual connection facility are recommended to be standardized for specific consumer's classes, at least for consumers connected at the low voltage network. |
| 6.5<br>CLASSIFICATION OF COSTS COMPONENTS AND TARIFF DESIGN | Due to the constraints imposed by practical considerations (e.g. metering infrastructure, billing systems, social acceptance), the granularity of use-of-network tariffs should be limited.<br>The tariff design should be flexible to adjust network tariffs to changing environment, to give more confidence to network operators as regards their cost recovery, and to balance conflict of interest of DSOs and connected prosumers.<br>Recovery of DSO's fixed costs should be based on the well balanced share of revenues |

| | |
|---|---|
| | to be collected through the hybrid solution applying fixed, volumetric and demand charges.<br>Monthly fixed charges should be set at a level of the customer-specific costs related to the metering, billing, collection and customer support services.<br>Demand charges weight in the tariff structure should be gradually increased to reach optimal balance of the cost reflectivity and the revenue recovery on the one side and energy, environmental and social policy goals on the other side.<br>Remaining DSO's revenues should be recovered through the volumetric network tariffs.<br>Network use tariff design should not have distortive effects on energy efficiency programs and heating fuel price parity, should take into account protection of vulnerable consumers and should not encourage disconnection of the prosumers with storage facility.<br>For residential and small commercial consumers, demand charges should be based on the contracted capacity with the power band pricing scheme, allowing consumers periodically, but not seasonally, to change the contracted capacity. Introducing a demand charge that is based on the measured peak demand might be gradually implemented, depending on the roll-out of smart meters.<br>Consumers should be offered with ToU volumetric tariffs as a default pricing option, preferably without opt-out possibility to revert back to flat pricing model.<br>Geographically uniform network tariffs are recommended to be applied provided that inter DSOs compensation scheme is administratively and economically feasible.<br>Electricity bill must be easy to understand and its structure should be kept as simple as reasonably possible in circumstances when number of tariff components, different levies and taxes is likely to be increased. |
| 6.6<br>ELECTRICITY TARIFFS FOR PRODUCERS – G CHARGES | Energy and capacity based G-charges should not be applied at the distribution level.<br>Reactive energy consumed by power plants while generators are in operation should not be charged.<br>Locational generation signals should be provided on a cost-reflective basis through the appropriately designed deep connection charging regime with limitations related to the grid reinforcement costs sharing.<br>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. |

# 7 EX-POST ADJUSTMENT

Ex-post adjustment may be applied to compensate the DSO's excess/deficit revenues during the regulatory period.

Regulator should set clear rules for adjusting revenues of the regulation period.

Some previous considerations are needed to make actual and allowed revenues comparable, since the actual profit or total revenue is also a result of the DSOs activities. Regulators should allow DSOs to retain the part or full benefit if they outperform their incentive target, but also DSOs who underperform should bear the additional costs.

Analysis and ex-post revenue compensation may be applied regarding the:

- Impact of volume and demand variations on DSO's revenues,
- Depreciation deviations,
- Non-controllable costs deviations,
- DSO operational efficiency performance under incentive schemes,
- Physical decrease of energy losses,
- Price of energy losses,
- Quality of supply performance under incentive regulation,
- Difference in actual and allowed R&D costs,
- Revenues from illicit consumption (if envisaged by General Terms and Conditions),
- Revenues from non-standard quality of supply services and
- Revenues from excess demand penalty fees (above the consumer's contracted capacity) and from excess reactive energy consumption.

In specific cases, when costs of debt can not be estimated with sufficient certainty, this parameter might be subject of ex-post adjustment too.

DSOs should be protected from the volume risk to avoid uncertainty of revenue collection that is a consequence of volume reduction. Vice versa, adjustment of actual revenues also protects end users from over-recovery of costs in case that electricity consumption has increased. Regulator should decide whether the volume risk is shared between DSO and end users, or it is entirely borne by the users.

Non-controllable costs should be adjusted too, to have them passed through to consumers if actual level is higher than estimated and vice versa to pay them back to consumers if DSO's savings occur.

Operational efficiency savings/additional costs are applicable if the incentive regulation is in force and DSO actual operating costs are at the level that is different from the set targets. The difference between actual and approved operating costs should be exempted from the adjustment, thus allowing DSO to keep savings from increased operational efficiency and vice versa to bear additional costs if performing worse.

A DSO should be allowed to keep the entire economic benefit from a reduction of its physical network losses compared to the approved level, and vice versa a DSO has to bear the entire additional costs associated with increase in the physical losses.

In case that DSO's efficiency savings are not exempted when performing the ex-post adjustment, the fundamental principles of incentive regulation would be breached. This situation is also known as a ''clawing back'' - term used to denote a retrospective adjustment by which the benefits of a company's extra efforts to improve efficiency in one period are confiscated during the next regulatory period.

Adjusted revenue related to the deviation of actual quality parameters and the reference values is based on quality performance during the previous regulatory period.

With regard to the non standard quality of supply services, a DSO can additionally charge a customer for costs related to existing network when the customer requires quality or services that are usually not expected to be delivered as a standard network service. Revenues following these kinds of services should be kept out of actual revenue when making the ex-post adjustment, provided that these costs are not already included in revenue requirements.

Revenues from illicit consumption might be exempted from the revenue adjustment, thereby providing additional incentive for DSOs to decrease network losses.

Revenues from excess demand penalty fees are linked to the extra charges imposed on consumers in case that measured demand is higher than contracted capacity. Regulators may set higher unit prices of excess demand to incentivize consumers to objectively assess necessary network capacity. Those revenues are recommended to be kept out of the revenue adjustment process.

The decision on excess/deficit revenue balance towards zero over time is to be realized through tariff changes. Excess revenues must be reimbursed to the customers, while deficit is to be recovered. In order to avoid substantial changes in tariffs from year to year, it is necessary to make this adjustment in the period which is long enough to provide ''smoothing'' of tariff changes.

## 7.1 POSITIONS – EX POST ADJUSTMENT

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

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

Ex-post revenue adjustment and compensation should be applied regarding the:

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

Ex-post adjustment of DSOs revenues to adjust to the volume variations prevents DSO's exposure to non-controllable volume risk.

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

Sliding scale is recommended to be applied for sharing socio-economic benefits related to the actual quality of supply performance compared to the targeted parameters.

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

# 8 DISTRIBUTED ENERGY RESOURCES

## 8.1 INTRODUCTION

Technology development and declining costs are likely to cause large scale deployment of different distributed energy resources in the near future. Beside the distributed generators that have become common part of the distribution system in the last 15 years, emerging cost-efficient technologies as the energy storage, smart water heaters and ice storage air conditioners are likely to be widespread. At the same time, smart appliances and control system that can communicate with the network control centers are entering retail market. PV systems are also becoming ''smarter'' with deployment of new generation of smart inverters, usually with integrated storage facilities.

Integration of new resources brings a range of opportunities and challenges for the network operators, with the special attention to be paid on distribution network costs sharing and possible influence on low income consumers that can not afford such equipment. On the other side, those resources can provide a range of ancillary services like a system balancing, voltage support, frequency control, black start capabilities, demand side management and other services. In that sense, they can be treated as the capacity resources that can increase reliability of supply, particularly if DG system is equipped with the smart inverters.

Under specific conditions when DGs are located at strategic points on the distribution network and their production and peak demand coincides all the time, DGs may defer or avoid investment in grid reinforcement. These conditions are likely to occur if PV generators are installed in the DSO areas which face annual peak demand during the summer as a consequence of space cooling.

## 8.2 INTEGRATION OF DISTRIBUTED ENERGY RESOURCES

Different pricing models can be needed to properly incorporate distributed energy resources, with regard to the distribution network services as well as the services provided by the consumers.

Pricing of distribution network services depends on the specific DER in subject, therefore new consumer's classes with installed DER should be clearly defined and distinguished.

Pricing of services provided by consumers is extremely complex issue requiring detailed study of individual services valuation for the system operation. In that sense, energy related services should be distinguished from the network related services that provide additional value to the system operators.

Different types of DER technologies that are currently deployed can be classified in the following groups:

- Distributed generators,
- Distributed generators for self-consumption,
- Distributed generators for self-consumption with storage systems,
- Back-up generators,
- Grid controlled water heaters,
- Grid controlled ice storage air conditioners,
- Stand alone storage systems,
- Electric vehicle charging systems,
- Other controllable loads.

Distributed generators currently represent the most mature DER technology, with the large scale deployment world wide.

With the growing DER deployment and sophisticated technologies that provides new DER functionalities and flexibility, aggregated service providers are emerging as the new players at the electricity market. Since the individual installed DER capacity is relatively small with the varied generation/load profile, it is possible to aggregate a variety of DERs into a virtual energy resource that can provide different balancing services like a conventional generation unit. Demand responses with curtailment or acceleration of loads, active control of storage system are examples of new emerging services that can be provided through aggregators. Regardless of the contracted services, consumers may be provided with the flexibility to ''override'' remote control and disengage participation from the program when their local needs are opposite to the DSOs or aggregators requirements. This type of arrangement can greatly improve customer program's perception and participation rates, but can violate electricity balancing market principles.

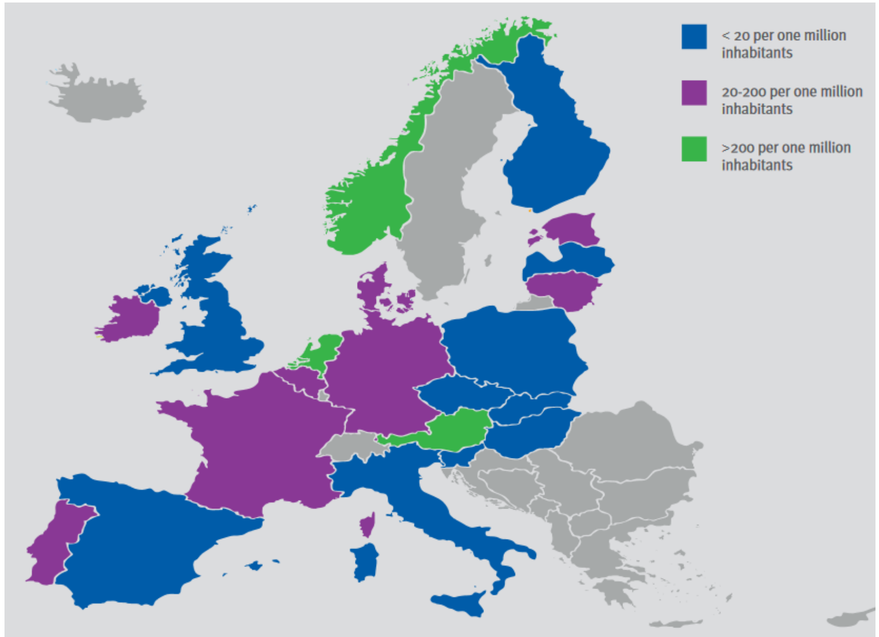
Threshold penetration for any DER technology can be defined as the sufficient numbers deployed so the combined generation/load is significant for system planning and operation purposes.

Electric vehicles are negligible part of load currently in the EnC, but their growth is likely to happen in near future together with the development of charging infrastructure. An electric vehicle annual consumption of 3.000-4.000 kWh if being used to travel 16.000 km/year is comparable to the consumption of average household[83]. At the start of 2017 there were about 75.000 of electric vehicles in Germany with 6.000 AC and 150 DC charging stations. On the other side vehicle-to-grid applications are currently at the very initial phase of development with ongoing pilot projects applied to test possibilities to provide back power to the grid during the critical hours.

Number of EV charging stations in Europe is shown in Figure 24[84].

[83] RAP Smart Rate Design For a Smart Future

[84] EURELECTRIC, Power Distribution in Europe Facts & Figures, p. 9




Source: EURELECTRIC (2013)

**Figure 24** *Number of EV charging stations in Europe*

By the end of 2016 in Germany about 50.000 of household and small commercial consumers had already installed small scale PV battery systems and it is expected that annual installation volume will reach 50.000 per year in 2020[85]. Large scale battery systems currently account for 144 MW installed capacity used for primary frequency control[86], out of which Li-Ion second life battery systems (used EV batteries) have installed capacity of 15 MW. This country is strongly supporting research in EV and stationary batteries with 80-85 million of € per year.

Quite large number of alternatives is available for charging network use services, as well as for payment for system services provided by DERs. Main principle that should be deployed while designing tariff system is to assure that DERs both pay a fair share of system costs and are eligible to receive fair remuneration for services provided to the utility system.

Network services pricing methods can be classified as follows[87]:

- Granular retail rates: A detailed, disaggregated rate in which each distribution service is priced separately and avoided through self-supply or otherwise paid for by the DER customer.
- Retail Buy/Sell arrangement: A bifurcated rate in which the DER customer pays a simple, bundled price for use of the distribution system and is separately paid for distribution services provided to the utility under a different pricing structure.

[85] GTAI, The Energy Market Storage in Germany, p. 2
[86] GTAI, The Energy Market Storage in Germany, Issue 2017/2018, p. 3
[87] BL, Distribution System Pricing with Distributed Energy Resources, p. 16

- Procurement Model: Utilities procure distribution services from non-regulated third parties who aggregate the services provided by individual DER customers and compensate those customers accordingly.
- DER-specific retail rates: A different rate is offered to each class of DER customer to reflect the costs of serving that type of customer as well as the value of the services that the specific class of DER customers provides.

The four pricing models are not mutually exclusive, as one model may be best suited for a certain consumer class, while a different model may be a better solution for another class.

Taken to its extreme, the granular gate could result in a different price for virtually every customer. Further, it could include a disaggregated list of services and charges that would be difficult to implement. One example of granular pricing is a separate pricing of system peak coincident demand and individual consumer's peak demand, applying different unit prices in order to reflect granular costs of system capacity and individual feeder capacity respectively. Additionally, same consumer with the installed DG unit may be priced for exports to the grid if new capacity is needed to accommodate reverse power flow. The main advantage of this model is significant improvement in fairness that can help to remove unintended subsidies embedded in rates designed under the simpler models. This model is the most transparent one as it provides unit price for each distribution service. It is also applicable for consumers without DER.

The granular rate practical application can face difficulties and very high administrative costs of implementation. The very essential principle of ''simplicity'' of distribution tariff has to be observed requiring significant simplifications and approximations in the rate's design. Model's implementation would require advanced metering infrastructure and significant upgrade of billing and data management system, in order to provide tools for timely processing and invoicing of each individual service consumed or provided. This model will not be pragmatic for small consumers, and it may be attractive to aggregators only.

In the Buy/Sell model, the DER customer's transaction with the utility is bifurcated into two parts, whereby each customer pays for its use of the distribution system through a simple, bundled rate that does not account for services provided by the DERs. On the other side, services provided by the DER are paid through the bill credits or direct payments.

A main advantage of the Buy/Sell model is that it does not require any changes to the existing retail rate, as there is a need only to establish prices reflecting the value of the services that DER customers provide to the grid.

Many utilities across the United States already offer this pricing model in the form of demand response programs such as direct load control. For allowing the DSO to control the air conditioning system, customers are given the bill credit regardless on the service activation. It might be possible to prescribe additional payment for demand response activation event. Advantage of Buy/Sell arrangement is simplicity that provides all customers with the DER to be invoiced for the distribution services in the same manner through the use of standard distribution services tariff. Main disadvantage of this method is non explicit valorization of every specific service provided by different DER classes. Open issue is what should be included in the payment for services, as the utilities may claim that the payment should be based on avoided costs only that would otherwise be incurred by procuring the services from other resources (e.g., building flexible generation capacity, external voltage support procurement etc.).

Buy/Sell model may be an effective solution to pricing distribution services in environments where there is very limited ability to change the distribution rate structure for all customers, or where there is a significant difference between the retail rate and the value of services provided by DER customers. It allows the regular frequent updates of tariffs for services provided by DER consumers, independently from lengthy procedures for setting distribution services tariffs.

With the Procurement Model, utilities hold auctions or publish public tenders to procure distribution services from DERs. Third parties submit bids to the utility and, if selected, aggregate the services of individual DER customers to respond to the DSO requirements. Compensation to the customer would be based on a contract established between the customer and the third party, as usually there is not direct contractual relationship between DSO and consumers. This method might be seen as the application of well established processes of TSO procuring different ancillary services, now at the distribution level.

This Model is probably the most effective model for full integration of DERs into DSO's long-term system planning activities, as the DSO defines the products based on its planning needs. One example of this model is long term provision of peak demand reductions, which would allow the utility to plan to defer capacity upgrades over that time frame in those geographic areas. Additionally, this model is simplistic from the customer's perspective, as they are expected to take part in the bidding process through an aggregator, thus avoiding to face complex pricing structure. Procurement model is location oriented, as the DSO procures the services in the areas where they are truly needed. From the cost perspective, DSO is not exposed to risk of uncontrollable expenses, as the DSO fully controls type and quantity of services and the available budget.

Main disadvantage of procurement model is that it does not influence the existing tariff structure, thereby not correcting any inequities and unfairness among the consumer's classes. In addition, application of this model may expose DSO to the risk of cost recovery, as the consumer's with distributed generation could be exempted from paying the real costs of distribution services provided. To mitigate the risk of cost recovery, procurement model should be amended with the change of existing tariff rate design regarding the prosumer's charging for network services. Administration costs can be too high if the complex services are procured, for the DSO and aggregators too, thereby decreasing the incentive to participate.

With the DER-Specific Rates model, a different distribution rate is offered to each class of DER customer. The rates are designed to reflect the specific costs of serving those customers, as well as the value of the distribution services provided by those customers. Initial precondition for the application of method is establishment of consumer's subclasses. To create specific subclass it is also necessary to have sufficient number of installation deployed. Additionally, it would be necessary to conduct cost of service study for each specific subclass, in order to determine the real distribution services costs and contributions. The DER-Specific Rates model is more complex when compared with the Buy/Sell model, but it provides better cost reflectivity as each specific DER class is individually assessed.

The DER-Specific Rates model avoids the need to change rates for non-DER customers, thus allowing more expedient transition to the new pricing structure. This model contributes to resolving the issues of DSO cost recovery and cross subsidization, as it allows creation of consumer's subclasses that have their own cost of service in proportion to use of the grid. By the appropriately designed tariff structure, this model may address any concerns about cross-subsidies between customers who have distributed generation and those who do not.

The DER-Specific Rates model can be applied as a solution for the tariff design regarding the consumers with installed distributed generators for self-consumption purposes. In order to avoid cross subsidization among consumers classes and possible negative impact on the DSO cost recovery, there is a need for the changeover from volumetric network tariffs to capacity tariffs for this specific subclass of DER consumers[88]. This change is supposed to involve only those specific consumer subclasses, possibly without any changes of underlying rate structure of the remaining consumers.

Demand analyses are needed to determine whether prosumers with integrated storage systems are reducing peak demand in comparison to the prosumers without storage system and other non-producing consumers of the same category and whether they should bear the lower capacity expenses as a result of reduced peak demand. Reasonable assumption is that installed storage system leads to peak reduction since average self-consumption share of PV generated electricity can be increased from cca 35% to more than 70% with the use of battery.

Cost-of-service study should be conducted for each specific DER consumer’s subclass prior any changes of the tariff design. Number of classes to be studied is expected to increase with the technology development, consequently requiring tariff design to be upgraded. Number of consumer’s subclasses should be kept reasonably low to avoid over complexity of tariff structure. A subclass definition requires that this group of consumers is sizeable and distinct from other subclasses and also homogenous with regard to the cost of distribution service and the value provided to the grid.

At the current stage of DER deployment, it is possible to define new DER consumer’s subclasses, as follows:

- Consumers with distributed generation for self-consumption;
- Consumers with distributed generation for self-consumption and integrated storage system;
- Electric vehicle charging stations.

***Clear distinction and valuation of distribution network related benefits from the social and energy supply related benefits is needed, as remuneration may only reflect DER services that are related to the distribution network operation.***

[88] For more information please refer to EnC ECDSO-E Task force, Distributed Generation for Self-Consumption, Key Aspects and Recommendations of Good Practice

## 8.3 POSITIONS - DISTRIBUTED ENERGY RESOURCES

DER-Specific Rates model is considered as the optimal, with the gradual introduction of new DER consumers' subclasses once the level of deployment is sufficiently high.

Tariff design should be timely adjusted regarding the tariff components 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[89].

Tariff rates for electric vehicle charging stations should incentivize car's charging when energy costs are low during the off-peak period. Time-of-use default rates for this class should be obligatory, with introduction of 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 DSO and contractually agreed between the parties.

Remuneration should only reflect DER services that are related to the distribution network operation.

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

[89] For more information please refer to EnC ECDSO-E Task force, Distributed Generation for Self-Consumption, Key Aspects and Recommendations of Good Practice

# 9 FUTURE REGULATION CHALLENGES

**Distributed energy resources integration and tariff design**

Each type of distributed energy resources has its own power characteristics and their integration and large scale deployment shall make tariff design exceptionally complex. Number of consumer's classes is expected to grow to properly reflect the network usage pattern and costs of different DER technologies.

Full value of distributed energy resources for distribution network operation is not known yet; this issue is likely to pose a new challenge for regulators to establish a financial framework for DER services compensation. Some services like a fault-ride-through capability, voltage and frequency regulation are difficult to be valuated.

Regulatory framework should be flexible to allow case-by-case evaluation of DER services in exceptional situations when DER installation or services in critical area are requested by DSO either to support grid operation or to postpone and even defer network reinforcement. Under these conditions value of DER services may be assessed using avoided costs of network reinforcement and network losses.

DERs should also be included in the power system security analyses when the level of deployment becomes sufficiently high to influence system security and contingency analyses.

**New risks related to DER and energy efficiency deployment**

If DSO recovers costs mainly through the volumetric network tariffs, it is very likely that DSO shall be exposed to new risks that are direct consequence of DG installations for self-consumption and energy efficiency measures.

The decline in the price of PV panels and battery storage, together with different public policy incentives for integration, are expected to boost their deployment to the level when adverse impact on DSO revenues can not be further considered as a negligible. In addition, there is no guarantee that prosumers with storage system will always need to remain connected to the grid, in case that island operation is viable from technical and economic point of view.

DER and energy efficiency related emerging risks that are likely to be relevant in future are:

- Risk of stranded assets,
- Lost revenue risk as a result of decreased consumption,
- Lost revenue risk as a result of net metering scheme (if scheme is allowed).

Regulatory framework is expected to address disruptive threats by providing risk mitigating mechanisms to avoid potentially adverse impact on the DSOs revenues, credit rating and access to capital market.

**Integration of Aggregators**

Aggregators are likely to appear as a number and functionalities of DERs are being increased. They can provide small consumers with possibility of market empowerment that is otherwise difficult to be achieved. Aggregators may provide different services such as demand response, storage control, spinning reserve, replacement reserve, purchase of prosumer's excess energy etc.

In its proposal of new Directive on a common rules for internal market in electricity (from February 2017), the EU Commission introduces the concept of aggregators and independent aggregators, where an independent aggregator is not affiliated to the supplier of the relevant consumer or the supplier's balance responsible party.

A clear distinction of aggregator's services that may be provided for DSO's purposes from the services provided at the electricity market or to the TSO, should be provided, as the DSO can only be liable for the services linked to its operational aspects, such as congestion management and the voltage regulation at the distribution level.

Recommendations regarding tariffs simplicity and granularity should not be rigidly applied for contracting services between aggregators and DSOs, but increased complexity should not be transferred to the consumers in any case.

**DSO and energy efficiency duties**

If DSO has a duty of active participation in the energy efficiency programs and targets achievement, DSO faces conflicting task to contribute to overall consumption decrease that directly decreases its revenues.

Regulatory task is to provide incentives for DSOs to take proactive role in achieving energy efficiency objectives through a predictive mechanism to compensate and reward DSOs for the lost revenues due to energy savings on customers' side.

**Ageing distribution infrastructure**

Ageing distribution infrastructure is a general problem faced by majority of European DSOs since majority of network assets had been constructed during the 1960s and 1970s. Pending network assets replacement with increased development needs driven by DGs installation, uneven consumption trends and smart grids initiatives are pressing DSOs to undertake costly investment cycle. Although general consumption level might stagnate, consumption increase in urban areas is expected as a result of population migrations, thus causing the assets stranding in rural areas.

Stability and predictability of the regulatory framework and fair rate of return on investments are once again emphasized as the key determinants of network development sustainability.

**Smart meters infrastructure**

If smart meter deployment is based on the positive cost-benefit analyses, investment costs should be recovered in the long term through depreciation and appropriate rate of return. Alternative approach to provide investment recovery is by a special rider added on electricity bill, but this solution is less preferred as it increases bill complexity.

On the other side, operating costs should be reduced in proportion to the net savings and benefits provided by the smart meters installation. Smart meters should not be considered as a pure consumer oriented costs, as a number of benefits are related to the energy savings, losses reduction, theft elimination, improved asset's utilization, outage management etc. Therefore only a relevant portion of smart meters investment may be allocated as a part of monthly fixed charge per consumer. However, monthly fixed charge is expected to be reduced as a result of benefits related to meter reading, billing and collection.

Relatively short lifetime of smart meters in comparison with the conventional electricity meters, in the range 12-15 years, gives rise to additional concerns about future costs of network service. Although the price of smart meters is competitive to the price of conventional meters, shortening a lifetime shall roughly double depreciation costs of electricity meters.

**Extreme weather conditions and emergency preparedness**

As a consequence of frequent extreme weather and natural disastrous events, distribution network infrastructure is exposed to increasing damage and devastation risk. DSOs have to cope with increased costs of emergency handling, such as stocks, assets repair and disposal, increased ENS etc. Capital costs are likely to be increased too, since network elements and equipment design criteria might be enhanced regarding their resilience on wind, ice, flooding etc.

Emergency handling and preparedness costs are expected to grow and should be recognized either by the appropriate cost recovering scheme or by the increased insurance costs.

**Increased expectations of better quality of supply**

Quality of supply incentive regulation and social non-acceptance of poor quality are putting DSOs under strong pressure to provide continuous improvements. In the same time, legislation is becoming more stringent with significant financial consequences for DSOs in case of incompliance with the quality standard.

Better quality of supply is not achievable without the increase of capital and operating expenses. It poses difficult challenge before the regulators to find reasonable trade-off, but generally speaking costs related to the quality of supply are anticipated to grow.

**Innovation incentive system**

R&D schemes are new regulatory issue in EnC CPs, supposed to provide continuous incentives for DSOs activities which would not be undertaken without such a scheme in force. Although increasing overall level of costs, it is recommended to incorporate those ad-hoc schemes to become standard part of regulatory framework, thereby requesting DSOs to keep a pace with technology development.

# 10 CONCLUSIONS

This report is based on theoretical and practical consideration of the key aspects related to the network tariff regulation. Beside the other goals to be achieved by this report, intention was to show how large number of inputs is needed for network tariff setting and to provide reasonable level of details depicting variety of solutions applied across the EU and EnC CPs.

Each local regulatory system has own specificities and it is quite difficult to provide tariff setting principles that can be used as a common basis for each regulatory authority. A number of examples provided by this report show the big differences even within EU countries that had established very specific national regulatory frameworks. Differences are observed regarding the applied regulation models, but also with regard to the most important revenue setting inputs, such as RAB valuation, WACC, level of losses etc.

In that sense these non-binding guidelines aim to provide the minimal set of positions and recommendations which are based on economic parameters and criteria that can be used by regulatory authorities to set reasonable cost-reflective tariffs. It is hard to expect that national regulatory frameworks will converge immediately, given the current diverse nature of regulation. Therefore, primary target of this Paper is a reasonable level of harmonisation of underlying principles for tariff setting, with a full awareness of implementation challenges. In addition, a risk of political influence and interference is expected not to vanish, due to a strong public susceptibility to energy prices. In that sense, it is likely that setting the distribution tariffs on the basis of purely economic criteria will cause retail electricity prices to increase, what will be very controversial for all national governments.

Regulatory framework should be stable and predictable, based on the clear rules regarding the key regulation parameters such as: assets valuation methodology, depreciation methodology, depreciation periods, network losses, operational efficiency and QoS requirements. Stability and predictability of the regulatory framework directly mitigate the level of risks faced by DSOs, which in turns provides lower costs of borrowed capital, lower rate of return and in the end the lower retail electricity prices.

Following detailed examinations of all important aspects of distribution tariffs regulation, we can conclude that the regulatory arrangements are to be moved towards more sophisticated incentive regulation methods. Optimal regulation method is assumed to be a hybrid one in order to better address specific issues of incentive regulation. Revenue cap regulation method is generally recommended to be applied as the next step of regulation development.

Incentive regulation should be introduced with regard to the cost of distribution losses and may also include simple innovation incentives scheme at the first phase. During the second phase, the incentive regulation for the operational efficiency and quality of supply is to be incorporated in the distribution tariffs regulation. Quality of supply regulation should be based on SAIDI and SAIFI continuity parameters during this phase. In the same time regulators should strive to fulfill preconditions to introduce the ENS parameter in quality regulation.

If we consider recommended model of distribution tariffs regulation, disaggregated per the main cost components, we can summarize that:

- Capital costs are regulated using the rate of return regulation method and include recognized costs of depreciation and reasonable rate of return.

- Controllable operating costs are set using revenue-cap regulation method with efficiency targets. Yardstick regulation method is the most common method applied to set utility's efficiency targets.
- Non-controllable operating costs are not subject of incentive regulation and they are simply passed through to consumers.
- Costs of distribution losses are set on the basis of utilities past performance with the individually set incentive targets.
- Quality of supply bonus/malus are set as a percentage of annual revenue in relation to the difference between the actual and reference level of quality of supply. Performance-based regulation is the most common method applied for quality of supply regulation.
- Network innovation should be regulated separately by applying specific ad-hoc regulatory schemes.

Yardstick regulation method and Performance-based regulation method are recommended to be used as complementary tools to provide input data for the revenue-cap based regulation of electricity distribution activities.

Future regulation of distribution tariffs is inevitably moving to more complex methods that will consequently set challenging requirements for regulatory authorities to provide knowledge and resources to cope with the difficult task to set optimal regulation model in new dynamic environment. Costs of regulation are expected to grow as a consequence of increased staffing and experts' knowledge requirements.

# 11 ACRONYMS

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| ACER | Agency for Cooperation of Energy Regulators |
| CEER | Council of European Energy Regulators |
| CWiP | Construction Work in Progress |
| DER | Distributed Energy Resources |
| DG | Distributed Generation |
| DORC | Depreciated Optimal Replacement Cost |
| ECRB | Energy Community Regulatory Board |
| EnC | Energy Community |
| ENS | Energy Not Supplied |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| ERRA | Energy Regulators Regional Association |
| EWEA | European Wind Energy Association |
| HC | Historic Cost |
| HV | High Voltage |
| IHC | Indexed Historic Cost |
| O&M | Operation & Maintenance |
| QoS | Quality of Supply |
| RAB | Regulatory Asset Base |
| RAP | Regulatory Assistance Project |
| RAV | Regulatory Asset Value |
| RC | Replacement Cost |
| RoR | Rate of Return |
| RPI | Retail Price Index |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| ToU | Time of Use |
| WACC | Weighted Average Cost of Capital |

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